COMPTON

PETROLEUM CORPORATION

Vision Into Value

ANNUAL REPORT 2000

COMPTON
PETROLEUM CORPORATION

Corporate Profile

COMPTON Petroleum Corporation is a Calgary-based public company actively engaged in the exploration, development and production of natural gas, natural gas liquids and crude oil in Western Canada. The Company's capital stock is listed and trades on The Toronto Stock Exchange under the trading symbol CMT, and is included in the TSE 300 Composite Index.

Compton began operations in 1993 with $1 million of share capital, a small dedicated technical team and a large seismic data base. The objective was to build a company from the grassroots through internal full-cycle exploration, complemented by strategic acquisitions. Compton's goal was to create a company capable of long-term sustained growth with a primary focus on natural gas. Compton's focus and strategy have remained unchanged since inception. Eight years later, in 2000, the Company had attained average production of 14,812 boe per day, long-life established reserves of 50.5 mmboe, control of over 1,200 sections of land and a total net asset value of $625 million.

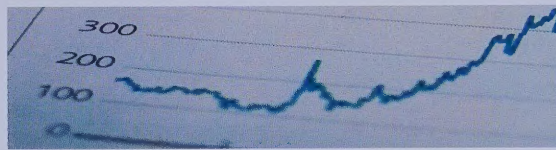
Annual Meeting

The Annual General Meeting of Shareholders will be held on Thursday, May 31, 2001 at 4:00 p.m. at the Calgary Chamber of Commerce, The Historical Ballroom, 517 Centre Street South, Calgary, Alberta, Canada.

Cover graph shows cash flow per share values.

Financial & Operating HIGHLIGHTS

→ COMPTON Petroleum Corporation



FINANCIAL

	2000	1999	% CHANGE
($000s except per share amounts)			
Production revenue, net of royalties	**168,681**	80,911	108
Cash flow from operations	**117,533**	49,030	140
Per share – basic	**1.10**	0.50	120
Per share – diluted	**1.06**	0.49	116
Net earnings	**40,059**	17,088	134
Per share – basic	**0.37**	0.18	106
Per share – diluted	**0.36**	0.17	112
Net debt	**153,590**	158,641	(3)
Shareholders' equity	**157,796**	116,702	35
Net capital expenditures	**118,472**	130,459	(9)
Common shares (000s)			
Issued and outstanding	**108,784**	108,047	1
Basic, weighted	**106,904**	97,409	10
Fully diluted, weighted	**110,645**	100,800	10

OPERATING

	2000	1999	% CHANGE
Production			
Natural gas (mmcf/d)	**85.1**	63.7	34
NGLs (bbls/d)	**1,897**	1,718	10
Oil (bbls/d)	**4,408**	2,756	60
Oil equivalent (boe/d) (10:1)	**14,812**	10,844	37
Oil equivalent (boe/d) (6:1)	**20,488**	15,091	36
Cash flow netback ($/boe)	**25.29**	15.21	66
Operating expenses ($/boe)	**5.82**	5.18	12
General and administrative expenses ($/boe)	**1.09**	1.07	2
Undeveloped land (acres)			
Gross	**763,503**	707,694	8
Net	**590,517**	502,404	18
Average working interest	**77%**	71%	8
Established reserves			
Natural gas (bcf)	**337.5**	289.0	17
NGLs (mbbls)	**5,352**	4,814	11
Oil (mbbls)	**11,367**	10,801	5
Oil equivalent (mboe) (10:1)	**50,473**	44,513	13
Oil equivalent (mboe) (6:1)	**72,969**	63,778	14
Finding and onstream costs ($/boe)			
Current year (10:1)	**10.42**	8.96	16
Current year (6:1)	**7.10**	6.62	7
Three year average (10:1)	**7.81**	6.92	13
Three year average (6:1)	**5.57**	4.82	16

Financial Success

Compton's focus on full-cycle exploration and financial discipline, complemented with strategic acquisitions, continues to deliver impressive financial performance. The Company's strong financial results in 2000 reflect its ability to transform this visionary focus into even greater value for the shareholders. Fueled by successful drilling, strong production growth and favourable commodity prices, the Company realized record revenue, cash flow, earnings and net asset value. This financial success continues to provide the Company with flexibility to expand its full-cycle exploration activities and to sustain long-term profitable growth.

Development

An integral aspect of full-cycle exploration is the development and production potential generated by Compton's successful exploratory program. In 2000, 60 new wells were brought on-production, contributing to the 37% increase in average production from the year before. A majority of this new production was brought onstream through Company controlled processing facilities and gathering system infrastructure. Control of area infrastructure and operatorship are two key components of Compton's strategy, providing the Company with competitive advantages in its core areas.

Vision into Value – Compton's

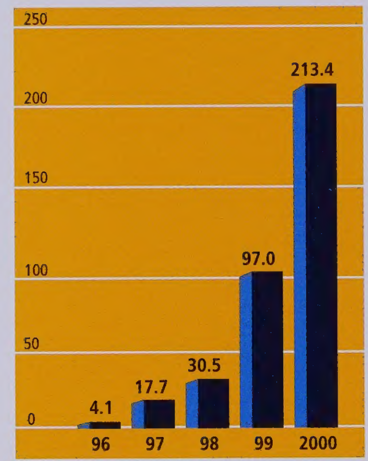
Investment

Compton's program of full-cycle exploration is directed at long-term growth. This ensures that all of the Company's assets must either offer potential for growth in reserves and production, or generate steady cash flow to fund growth of exploration prospects. In the mid-90s, Compton performed a series of strategic acquisitions to obtain both asset types, with a primary focus on lands with strong natural gas potential, plus key infrastructure. Once the full-cycle exploration process is established, new investment focuses on continually expanding the base of undeveloped land to maintain a growing inventory of drillable prospects. In 2000, Compton's capital program totalled $119 million.

Exploration

Compton's strategy for sustainable, long-term growth involves pursuing deeper targets with bigger pools that will produce at strong rates for years to come. Having assembled a line-up of high-potential properties in the mid-to-late 90s, Compton's operational focus shifted to growth through the drill bit in 1999 and 2000. Last year the Company drilled 96 gross wells, and of the 86 wells it operated, 53 were classified as exploration wells. Compton's average well depth was twice as deep as the typical Alberta shallow-gas well. Despite this exploration-weighted program, the Company achieved a drilling success rate of 70%, and the 2000 drilling program generated 9.8 mmboe (10:1) in new reserves.

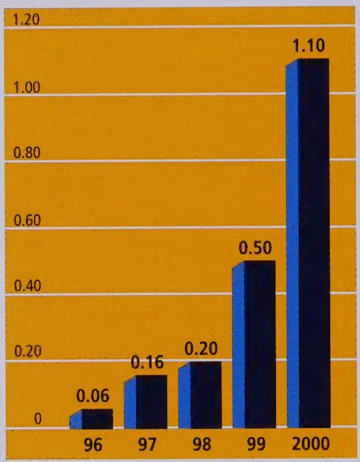
repeatable full-cycle model



TOTAL REVENUE

[$ millions]

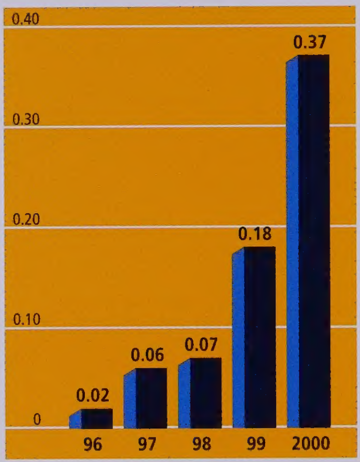
Compton's natural gas weighting and increased production, as well as higher commodity prices, led to large revenue gains in 2000.



CASH FLOW

[$/share]

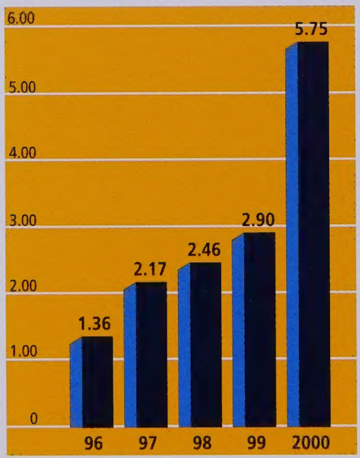
Year-over-year growth reflects a combination of successful full-cycle exploration, growing production, control of costs, financially accretive acquisitions and strong commodity prices.



NET EARNINGS

[$/share]

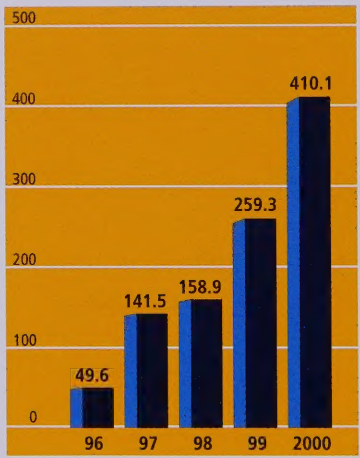
Earnings more than doubled from one year ago, and represent 24% of net revenues, a strong indication of Compton's financial success.



NET ASSET VALUE

[$/share]

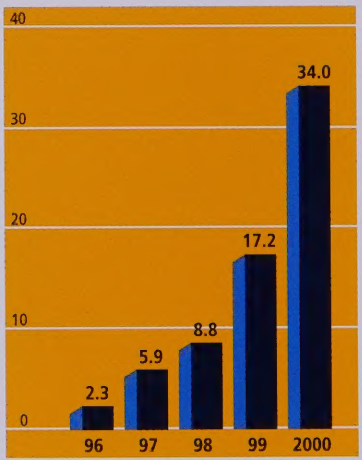
Continued commitment to a natural gas focus and a balanced risk portfolio is reflected in strong and growing net asset values.



MARKET CAPITALIZATION

[$ millions]

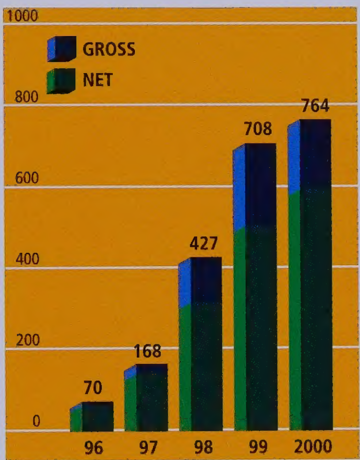
The large increase in year-end market capitalization reflects the strength of Compton's share price and investor confidence.



RETURN ON EQUITY

[%]

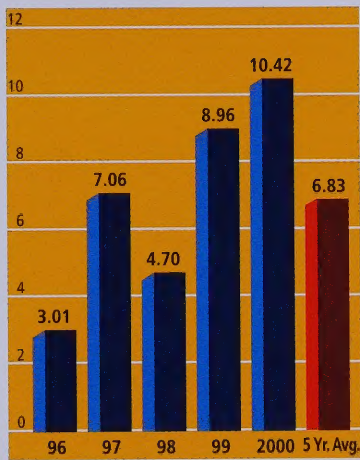
Successful full-cycle exploration and profitable growth has delivered superior returns on equity.



UNDEVELOPED LAND

[000 acres]

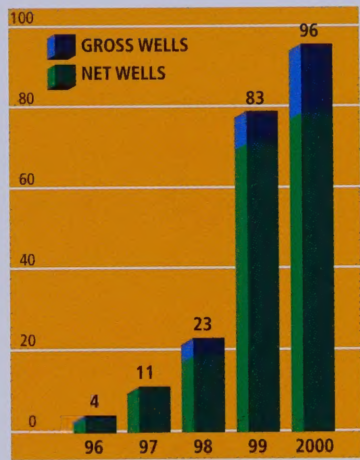
Compton's undeveloped high working-interest land acreage increased in 2000, further enhancing the Company's prospect inventory.



FINDING & ONSTREAM COSTS

[$/established boe] [10:1]

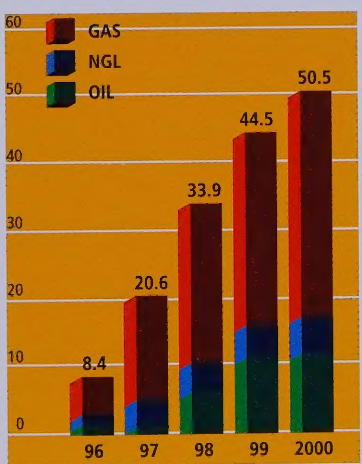
Over the past five years, capital expenditures were incurred at a competitive average cost of $6.83 per established boe.



WELLS DRILLED

[total]

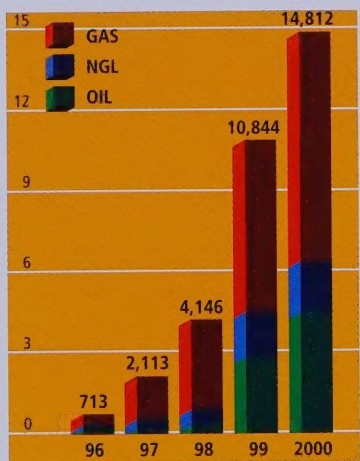
Compton executed an aggressive drilling program of 96 wells (53 exploratory), with a total success rate of 70% and an average depth of approximately 1,730 metres.



ESTABLISHED RESERVES

[mmboe] [10:1]

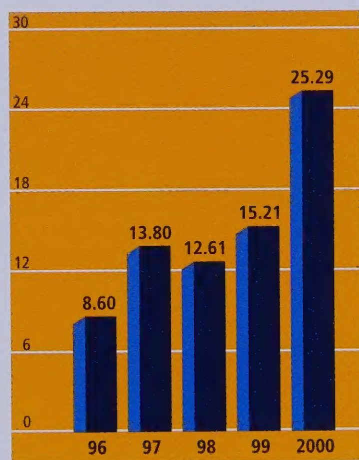
Compton's drilling success translated into strong growth in reserves; discoveries in 2000 were weighted towards natural gas and replaced the Company's production over 2 times.



PRODUCTION

[boe/d] [10:1]

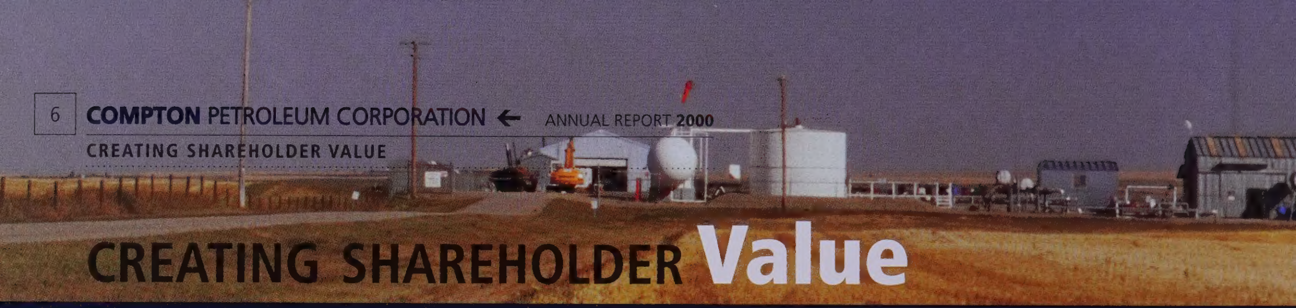
Compton's production is levered 77% towards natural gas and natural gas liquids.



NETBACKS

[$/boe][10:1]

A natural gas weighting and strong commodity prices generated higher netbacks in 2000, creating a strong financial base for reinvestment.



CREATING SHAREHOLDER Value

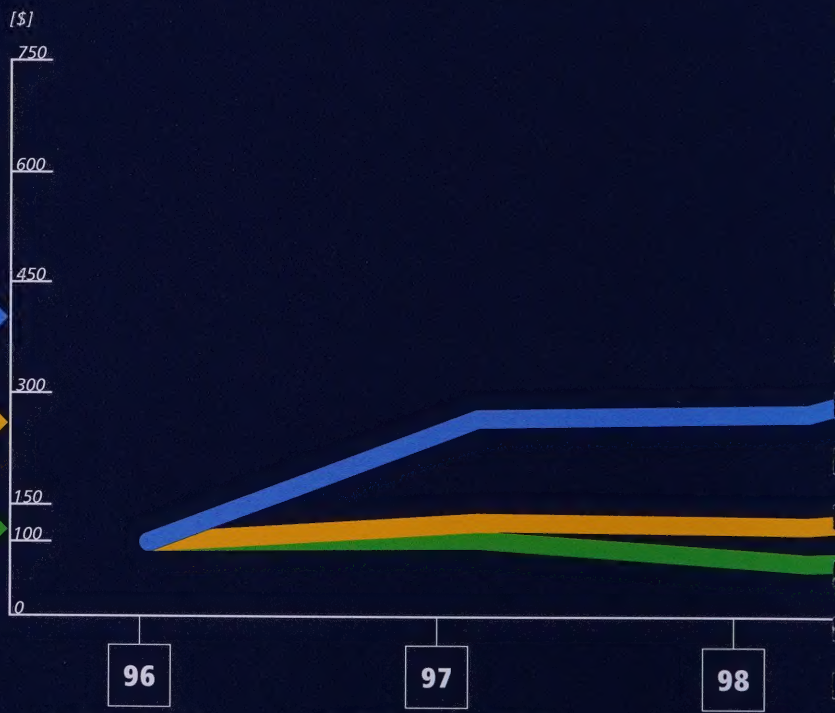
→ **SINCE ITS INITIAL PUBLIC OFFERING IN 1996,** Compton has outperformed the TSE 300 Composite Index and the TSE Oil and Gas Producers Index. This impressive investment return performance is indicative of our shareholders' ability to participate in the Company's success through share price appreciation.

Cumulative value on $100 invested from September 30, 1996 [date of the listing of the Company's common shares on the TSE]

COMPTON →

TSE 300 COMPOSITE INDEX →

TSE OIL & GAS PRODUCERS INDEX →



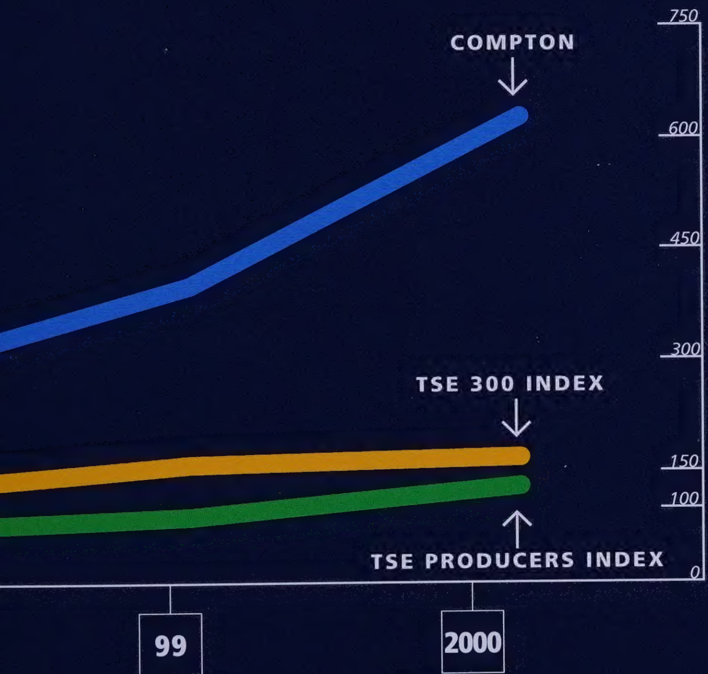
On September 30, 1996, Compton completed its initial public offering at $0.60 per share and commenced trading on The Toronto Stock Exchange.

During 1997, the Company established itself as a dominant player in Southern Alberta by acquiring interest and operatorship of the Mazeppa Gas Plant and various working interests in lands and wells in the Okotoks and Gladys areas.

In December 1998, Compton acquired J.M. Huber Canada Limited, establishing Bigoray – West Central Alberta and the Peace River Arch – Northern Alberta as core areas for the Company.

RETURN ON EQUITY [%] →	96	97	98
	2.3	5.9	8.8

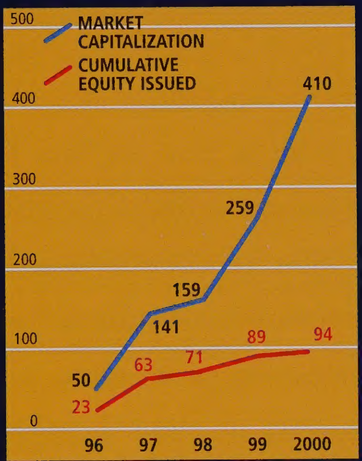
COMPTON'S GLADYS GAS PLANT



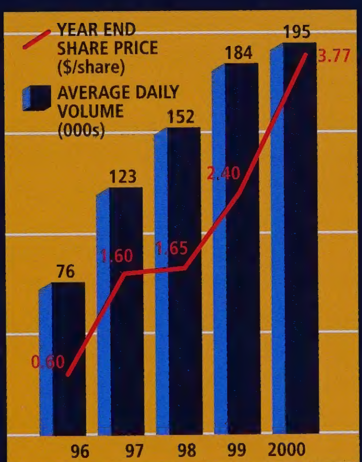
In December 1999, Compton acquired Coparex Canada Limited, further enhancing Compton's presence in the Peace River Arch area.

In 2000, Compton continued to aggressively expand in each of its four areas. The Company executed a record exploration and development program to capture new reserves and bring on-production 60 new wells.

17.2 **34.0**



MARKET CAPITALIZATION vs CUMULATIVE EQUITY ISSUED
[$ millions]



TRADING LIQUIDITY vs SHARE PRICE

Since its initial public offering in September of 1996, Compton has delivered excellent year-over-year share price appreciation with high levels of trading liquidity.

** Share Price reflects year-end closing price except 1996 which reflects IPO price of $0.60.*

E.G. SAPIEHA, *President and Chief Executive Officer*

President's LETTER

I am pleased to present Compton's results for 2000. This year's annual report reflects our strong financial and operational accomplishments and determination to continue to transform Compton's vision into even greater value for our shareholders. Revenue, cash flow, earnings and net asset value more than doubled from the year before. Fueled by our drilling successes, growing production, and strong commodity prices, return on shareholders' equity reached its highest level ever.

CONSISTENT STRATEGY

Compton's vision and strategy has been consistent since our inception in late 1993 with only $1 million of equity. This strategy has been to build from the grass roots a company focused on long-life natural gas reserves, capable of sustaining long-term growth and value creation for our shareholders. Over the last seven years, Compton has successfully executed this strategy and we continue to expand this vision and create significant value.

The soundness of this vision, and the ability of our team to turn it into measurable reality, are demonstrated in our 2000 operational and financial results:

GROSS REVENUE	***Increased 120%***	TO $213 MILLION;
CASH FLOW	***Increased 140%***	TO $118 MILLION;
EARNINGS	***Increased 134%***	TO $40 MILLION;
NET ASSET VALUE	***Increased 98%***	TO $5.75 PER SHARE;
AVERAGE PRODUCTION	***Increased 37%***	TO 14,812 BOE PER DAY (10:1);
ESTABLISHED RESERVES	***Increased 74%***	TO $678 MILLION (10% DCF)

Compton has grown significantly from 1993 to a company with a current net asset value of $625 million. This success has been due in part to our financial discipline and adherence to our strategic vision. By remaining disciplined, Compton can continue to secure our long-term future and deliver tremendous results.

COMPTON'S MOST ACTIVE YEAR

During 2000, Compton continued to aggressively expand in each of our four core areas. The Company generated a record $118 million in cash flow and invested $119 million. We focused on all phases of the exploration cycle: land acquisition, seismic, exploratory and development drilling — including 96 gross wells, our largest program ever. Our capital program was aimed at generating both immediate cash flow, infrastructure improvement, and strengthening our foundation for long-term growth.

The Company's finding and development cost of $10.42 per boe (10:1) was in the mid-range of our peer group, however, it was above Compton's initial 2000 target. During the fourth quarter of 2000, Compton deliberately doubled its budgeted capital expenditures in land, seismic and production facilities. These spending targets were purposely exceeded as a direct result of our drilling success.

Compton's capital expenditures are summarized as follows:

Capital expenditures	($ millions)	F&D cost per boe (established reserves) (6:1)	(10:1)
Land and seismic	$ 23.3	$ 1.40	$ 2.05
Drilling and completions	66.7	4.00	5.86
Facilities	28.5	1.70	2.51
	$ 118.5	$ 7.10	$ 10.42

SOUTHERN ALBERTA

Compton invested significantly in land, seismic, drilling and pipeline infrastructure resources in its large Basal Quartz discovery in the Hooker area, 50 miles south of Calgary. The Company now controls more than 150 sections of land directly on-trend. We achieved our objective of exiting the year with Hooker production of 25 mmcfe per day and booked reserves of 83 bcfe. This exciting deep, tight, long-life, and low-decline sandstone play currently has only 20 developed sections out of 150 sections, representing many years of growth potential for Compton.

Compton has also aggressively pursued its shallow gas program around the Gladys area just south of Calgary, drilling approximately 20 wells and installing new facilities. Although initially capital intensive with new pipeline requirements, this is an excellent project, with solid, low-decline reserves requiring numerous wells to achieve economies of scale. This project has now moved from a high-risk exploration program to a development project delivering steady cash flow and considerable upside.

The two other major exploration projects in Southern Alberta were the acquisition of 65 sections of land on the Tsuu T'ina Reserve and the shooting of a $2 million seismic program on the Stoney lands. Both Stoney and Tsuu T'ina are being extensively worked from an exploration basis and are very exciting, multi-zone potential projects with drilling budgeted for the third quarter of 2001.

CENTRAL ALBERTA

The Bigoray core area in Central Alberta continues to represent an important asset with stable, high-quality light oil and natural gas production. Compton's 2000 drilling activities in Bigoray centered on maintaining existing production and expanding our land base, and also resulted in a new pool natural gas discovery. Since acquiring Bigoray from J.M. Huber in 1998 for $42 million, this area has delivered solid results, cash flowing $30 million in 2000 and generating a year-end reserves value in excess of $100 million.

NORTHERN ALBERTA

During 2000, the Company's capital program in the Peace River Arch in Northern Alberta has resulted in increases in oil production and reserves, while maintaining stable gas production and reserves. This is an emerging exploration area for natural gas with high expectations for growth. We are very pleased with our oil development program in the Cecil area, which has exceeded our initial expectations from both a reserve and production basis. We continue to remain enthusiastic with this area and exploration activity for natural gas in the Clayhurst area has been expanded to include a large seismic program and the expansion of our gas plant into a sour facility with the installation of an amine unit.

Compton's Rainbow area, with its large gas-prone land base of approximately 200 sections, holds significant potential. The Company's exploratory programs in the past have been modestly pursued, as this area presently offers only four months of winter access. Historically, this area has been characterized as very challenging because of the limited winter access, lack of year-round road systems, no sales pipeline, and no processing facilities. However, Rainbow has now become a very active area within the industry. A recently installed natural gas pipeline crosses directly through Compton's lands, two competing sour pipelines extend to the edge of Compton's

PRESIDENT'S LETTER

E.G. SAPIEHA, *President and Chief Executive Officer*

ERNIE SAPIEHA, C.A. *Director* **JEFF SMITH,** P.GEOL. *Director* **IRV KOOP,** P. ENG., *Director* **JOHN PRESTON** *Director* **MEL BELICH,** Q.C. *Director & Chairman* **TIM MILLAR,** LLB *Corporate Secretary*

lands and the surrounding acreage is experiencing a high level of drilling activity. To date, Compton has identified shallow gas Bluesky and Jean Marie potential and deep Slave Point and Sulphur Point potential. We are working on a significant first quarter 2002 drilling program and production tie-ins. This area is now positioned to compete with our other core area projects and provides significant growth potential for the Company.

FINANCIAL

Compton delivered impressive financial performance in 2000. Buoyed by growing production and strong commodity prices, Compton generated a cash flow netback of $25.29 per boe (10:1), compared to $15.21 per boe in 1999. Total cash flow was $117.5 million ($1.10 per share), an increase of 140% over $49.0 million ($0.50 per share) in 1999. Net earnings, which has consistently been around 24% of net revenue, grew to $40.1 million ($0.37 per share).

Year 2000 was the sixth consecutive year in which Compton delivered year-over-year increases in both cash flow and net income – a strong endorsement of the Company's strategy to sustain growth and long-term value generation. Return on shareholders' equity was 34%, compared to a return of 17% in 1999, marking the fifth consecutive year this key financial measure has improved.

Our financial position is also very strong. At year-end 2000 Compton's net debt position was $153.6 million. This represented a debt-to-cash flow ratio of less than 1.0 times annualized fourth quarter 2000 cash flow.

COMPTON'S EXPANDING VISION

While the Canadian oil and natural gas industry is enjoying excellent commodity prices, it is presently faced with a shortage of prospects and growth opportunities. It takes years to develop sustainable natural gas prospects from scratch, and as a result, oil and gas companies and royalty trusts have turned to mergers and acquisitions for growth. This trend has virtually eliminated the industry's "mid-cap" companies, those producing in excess of 15,000 boe per day (10:1 gas conversion) with a market capitalization of $400 million to $1 billion.

Compton finds itself in a unique position. With year 2000 production averaging nearly 15,000 boe per day, we are poised and can be successful at the "mid-cap" level. We have the solid foundation, experienced and talented people, an excellent track record of success, and the strong assets required to prosper as a deep natural gas explorer.

ERNIE SAPIEHA, C.A.
President & CEO

KIM DAVIES, P.GEOPH.
VP Exploration

NORM KNECHT, C.A.
VP Finance & CFO

MURRAY STODALKA, P.ENG.
VP Operations

The measure of Compton's potential for continued long-term growth is a reflection of our outstanding assets, both tangible and intellectual. They include:

- A strong balance sheet;
- A large gas-prone land base of more than 1,250 sections of lands and high working interests concentrated in four core areas;
- Expertise in deep natural gas operations with a five year average finding and development cost of $4.79 per established boe (6:1), or $6.83 (10:1);
- An established reserves base of one-half trillion cubic feet equivalent with long-life, low decline pools capable of funding exploration programs;
- Control of processing and transportation facilities for all producing reserves;
- A three year inventory of internally generated exploration and development prospects;
- A reputation for successful, value-adding acquisitions;
- An experienced and committed Board of Directors dedicated to enhancing and protecting shareholder value;
- Our most important asset — people. Our success flows from the teamwork of an experienced, dedicated and enthusiastic group of people who form the Compton team.

We have achieved excellent year-over-year growth in assets, production, cash flow and net earnings, as well as strong growth in return on equity. Each of our core areas has significant upside. Compton's growth, in other words, is sustainable. We have plenty of room to grow and add great value for our shareholders. We look forward to this challenge and the opportunities that lie ahead.

2001 DIRECTION

For 2001, Compton has a program of extensive exploration and development, potentially complemented with a strategic acquisition if a value-accretive opportunity arises. Our capital budget envisions drilling 120 wells, the majority of them in Southern Alberta. We presently have in place a budgeted capital spending program of $120 million, the majority of which will be invested in Southern Alberta, with a particular focus on our exciting Hooker play. The capital budget also includes expanded activity in each of our four core areas through drilling and land purchases. This projected level of capital expenditures is expected to increase average annual production by 15-20% from the 2000 level.

The Company has commenced 2001 with a disciplined capital program. Commodity prices continue to remain strong, however, drilling rigs and service costs have increased dramatically. The peak demand for these services, which are

PRESIDENT'S LETTER

E.G. SAPIEHA, *President and Chief Executive Officer*

MARC JUNGHANS, P.GEOL. *Exploration Manager*

TERRY MAH, P.ENG. *Engineering Manager*

GREG SHPYTKOVSKY, C.E.T. *Drilling Manager*

WADE MROCHUK, C.E.T. *Production Superintendent*

THERESA KOSEK, C.A. *Accounting Manager*

GARY FOLLENSBEE, P.ENG. *Aquisitions Manager*

GARRY McCULLOUGH, P.LAND. *Land Manager*

DEAN BERNHARD, C.M.A. *Finance Manager*

already operating at full capacity, typically occur between November and April because of winter access. As such, we have purposely geared our capital programs to expand in early June. At this time we will have a very good indication of the commodity price and service environment, and the outlook for our industry for 2001.

The Company presently remains tremendously flexible. Should natural gas prices average US$5 per mcf on the Nymex, and West Texas Intermediate crude oil average US$25 per bbl, our cash flow will greatly increase over the previous year. The Company can decide to significantly expand our capital program, buy back shares, reduce debt, or undertake an accretive strategic acquisition.

The value of Compton's 10% DCF established reserves, calculated by our independent engineers using constant price economics of US$5.50 per mcf and US$25 per bbl, is approximately $1.2 billion. If commodity prices continue to be strong, as we believe they will be, the upside for our shareholders is tremendous.

ACKNOWLEDGEMENTS

I look back on the Company's achievements with great satisfaction, and I look forward to 2001 with great optimism. Compton's financial and operating position is the strongest in its history, and we have the assets and talented personnel required to continue on our track of profitable growth. Year 2000's strong results have occurred as a result of the very dedicated and disciplined teamwork of Compton personnel. Moreover, the Company is led by a group of experienced managers, executives and directors with a high level of ownership and a successful track record of executing long-term strategies.

My sincere thanks go to every member of the Compton team, to the members of our Board of Directors and to you, our shareholders for your continued support.

On behalf of the Board of Directors,

E.G. Sapieha, C.A.
President and Chief Executive Officer
April 10, 2001

Core Areas AND PROPERTIES

COMPTON executed a record capital program in 2000 to find and develop new reserves and bring on production 60 new wells during a time of high commodity prices. Compton drilled 96 gross wells during the year of which 53 were classified as exploratory. This is the second consecutive year of drilling nearly 100 wells, demonstrating the Company's vision and commitment to growth through the drill bit. Compton maintained a drilling success rate of 70%.

The number of wells drilled does not tell the full story, however, because Compton is drilling deeper, on average, than the typical Canadian intermediate producer, on plays with low declines and significant natural gas reserve potential. Compton's 2000 program included 33 deep tests from 1,800-3,400 metres. Compton drilled an average of 1,730 metres per well on the 86 operated wells. The 2000 program continues Compton's emergence as a successful explorer of shallow through deep natural gas plays.

Southern Alberta is Compton's major exploration region, an area the Company pioneered during the late 90s. The opportunities here range from lower-risk shallow gas to new, high-impact deep Cretaceous sandstone and Paleozoic carbonate plays. Compton's current inventory of prospects has the potential to double its natural gas reserves by 2003.

In central Alberta, Bigoray-area oil production from Nisku and Cardium continued to provide strong cash flow to fund capital expenditures while offering ongoing potential for step-out and infill drilling and secondary recovery programs.

On the Peace River Arch, 2000 was mainly a year of establishing prospective plays and opportunities. The first phase of exploitation drilling increased Compton's crude oil production.

Natural gas in the West Rainbow area of northwestern Alberta has become economically viable with the extension of a Nova transmission line into the area and a strong natural gas price environment. Compton's unexplored northern Alberta area offers large multi-zone natural gas exploration potential for the longer term, while additional exploitation opportunities are present in the Rainbow and Zama basins to the northeast.

Compton maintains a three-year inventory of opportunities covering a spectrum of risk levels. With more than 1,250 sections of high-grade undeveloped land at year-end 2000 across its core areas, the Company is well-positioned to continue adding reserves and production at acceptable risk levels.

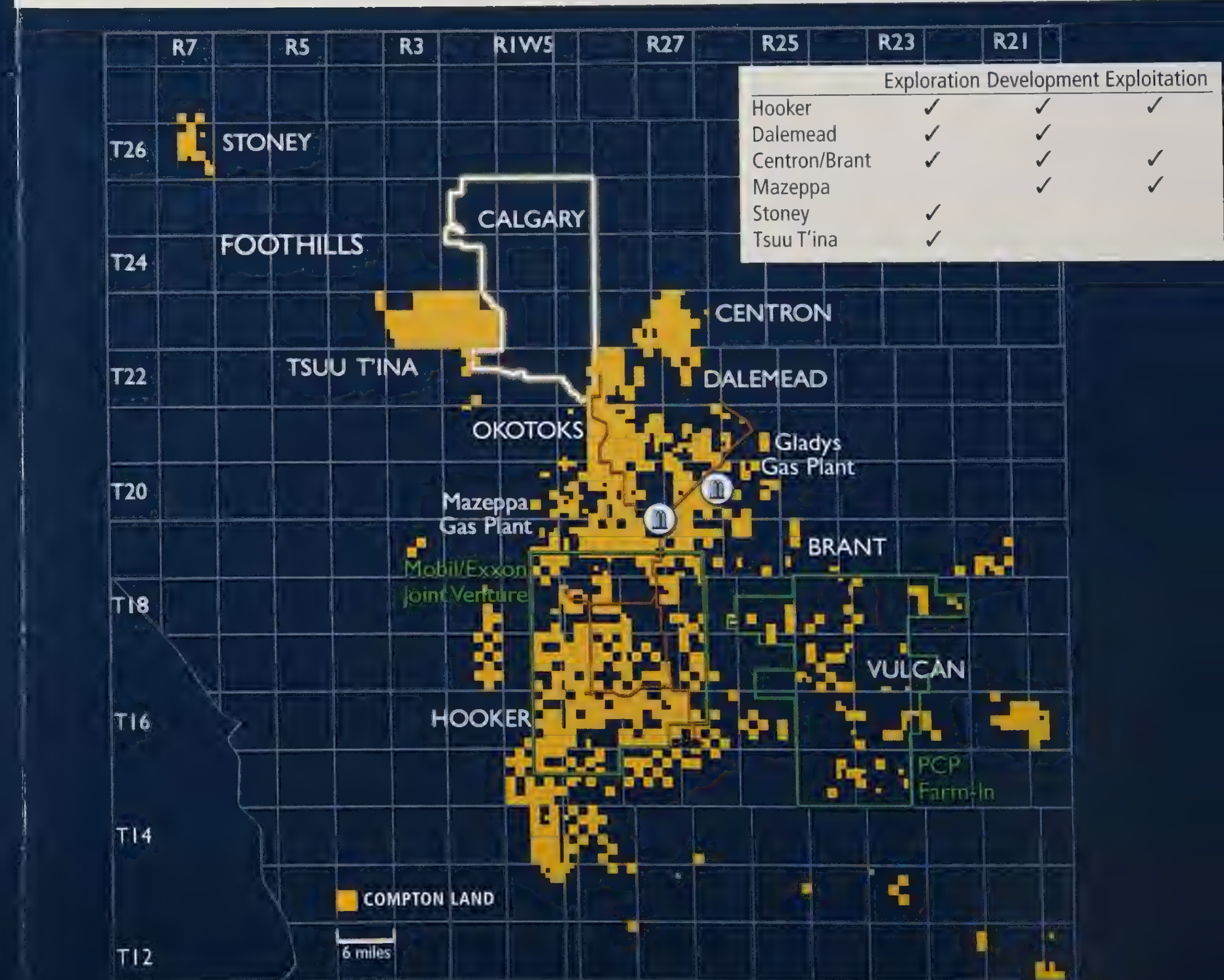
LAND

Compton spent a total of $23.3 million for land and seismic acquisitions in 2000. This included several major transactions in the Southern Alberta core area, including 70 sections, extending the Company's interests over the Hooker trends. In the first quarter of 2001, Compton acquired three additional significant blocks of prospective lands in Southern Alberta, consolidating the Company's holdings and accessing additional prospects. At Bigoray there is opportunity to acquire additional producing and drillable lands. Compton will also work to consolidate its holdings in the Peace River Arch through Crown land sales.

	SOUTH	BIGORAY-CENTRAL	PEACE RIVER ARCH	NORTH	TOTAL
UNDEVELOPED LAND (net sections)	410	185	163	204	962
2000 ANNUAL AVERAGE PRODUCTION (boe/d)(10:1)	6,334	5,437	2,864	177	14,812
2000 WELLS DRILLED	54	22	15	5	96
2001 WELLS TARGETED	72	29	16	3	120
2001 PROJECTED CAPITAL EXPENDITURES ($ millions)	76	25	16	3	120

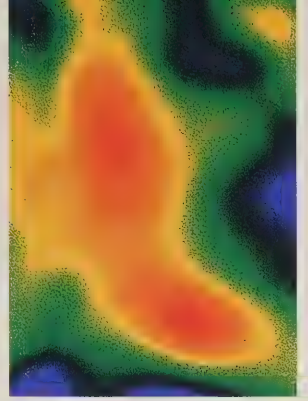
FOCUS ON Southern Alberta

Southern Alberta is presently Compton's major growth area, and commanded 52% of the Company's capital expenditures in 2000. This under-explored region offers multi-zone potential for natural gas and natural gas liquids with a mix of exploratory, exploitation and development plays. Compton has been active here since the Company's formation, and has assembled an enviable portfolio of shallow Cretaceous sandstone and deeper sour and sweet Cretaceous sandstone and Paleozoic carbonate natural gas production. Additionally, Compton has operatorship, control over area infrastructure, and guaranteed access to processing facilities. Compton controls more than 800 sections of land with the potential to add more in 2001 through existing farm-in opportunities.



THE Hooker PLAY

COMPTON'S Hooker pool discovery is the Company's most exciting exploration success to date. It solidifies Compton's credentials as an explorer of deeper, higher-impact natural gas opportunities, and holds the potential to double Compton's natural gas reserves over the next few years.



Low activity.

Compton recognized opportunity for multi-zone liquids-rich gas area.

CONCEPTS AND PLAYS

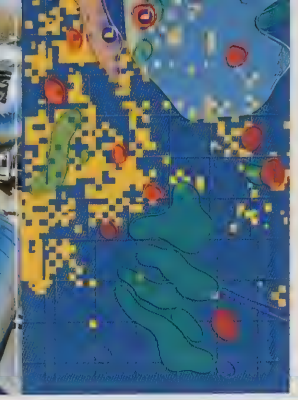
1996

Purchased Mazeppa gas plant and 50 bcf reserves from senior producer.

Doubled plant capacity and built pipelines.

CONTROL OF INFRASTRUCTURE

1997



Depressed commodity prices create opportunity.

Negotiated farm-ins on 405 sections of fee simple lands.

Sold Mazeppa plant at profit.

DOMINANT LAND POSITION

1998

March: Hooker Basal Quartz natural gas discovery.

Discovery well brought on-production at 3.5 mmcf per day.

Price revival begins in mid-year.

DRILLING SUCCESS

1999

Hooker outpost drilling accelerates; development drilling begins.

Booked 83 bcfe net established natural gas reserves.

Infrastructure development – 6" gathering line – enables production of 25 mmcf per day net to Compton at year-end.

Major Crown land acquisition on south end of Hooker Trend (Aphrodites).

DEVELOPMENT AND EXPANSION

2000

Sixty-five square mile 3-D seismic program.

Continue Hooker development.

Explore Basal Quartz gas trend north and south over six townships.

CONTINUED GROWTH

2001

Compton's technical staff recognized several years ago that a large area extending from Calgary to Claresholm remained underexplored despite being highly prospective for both shallow-depth natural gas and the deeper reservoirs. This opportunity had been held open through the mid-90s by low natural gas prices, the control of large acreage positions wielded by a few senior companies and a lack of available economical infrastructure options for transporting and processing natural gas. Compton implemented an innovative, counter-cyclical strategy to gain access to all prospective zones on more than 405 sections through two joint ventures. The three-year land-earning phase of these agreements commenced in 1998. The Company also initiated an aggressive Crown and freehold land acquisition program to further expand its land base.

The Lower Cretaceous Basal Quartz sandstone is an overlooked zone that is too deep for traditional low-cost shallow gas drillers and has been bypassed by deeper Paleozoic carbonate gas explorers. It can be a challenging reservoir, with low porosity and permeability. However, the potential for pay thickness of over 10 metres, and the higher pressure at the 2,800 metre burial depth, offer greater reserves per well than the shallower plays, with low annual decline rates. Wells of this type cost an average of $1.5 million to drill, complete and tie-in, and can access 5-10 bcfe of reserves.

In 1998, Compton explorationists recognized Basal Quartz gas potential in two old wells,and used geological and seismic data to map a reservoir fairway on the joint venture lands.

The Company's engineers were optimistic that modern well completion techniques, proven in the northwest Alberta deep basin, could bring the Basal Quartz on production at economic rates.

Compton drilled its first joint venture Basal Quartz prospect at Hooker in March 1999. The well was successful, making a new pool discovery. Following fracture stimulation of the reservoir, it commenced production at 3.5 mmcf per day. A gas liquids component of 15-30 bbls per mmcf of natural gas and the absence of free water in the reservoir add significant value to the play.

In 2000, Compton drilled 18 wells at Hooker, achieving a success rate of 79%, while continuing to map the play trend. Compton's 2000 wells were technically sounder, on average, than the 1999 wells, thanks to the Company's steadily increasing understanding of the reservoir. The Company built a new six-inch gathering line from Hooker to the Mazeppa plant to overcome an infrastructure bottleneck, enabling the Hooker property to produce 25 mmcfe per day of production at year-end 2000.

Compton has booked established reserves of 83 bcfe of natural gas to its average 75% working interest at Hooker, as evaluated by Compton's independent firm of petroleum engineers.

The Basal Quartz sand occurs in multiple channel trends throughout southern Alberta. In 2000, Compton moved to secure control of most of the Hooker fairway, by earning joint venture lands and purchasing additional Crown rights on a further 70 sections of contiguous land.

Five Years of Exploration and Discovery

Present Time

Five Years Ago

FIVE YEARS AGO
Inset map shows existing production from known reservoirs when Compton first entered the area.

PRESENT TIME
Large map shows extent of reservoirs currently on production. Compton has taken a significant and dominant interest in this prospect area.

OTHER Southern Alberta PLAYS

SHALLOW GAS

Strengthening natural gas prices motivated Compton to increase its shallow gas drilling and production activity at its southern Alberta properties in 2000. Compton has an extensive land position along a 40-mile stretch from Centron, northeast of Calgary, through Gladys and Medallion to Brant. This lower-risk target offers five sandstone objectives of Upper Cretaceous age at burial depths of 600-1,200 metres. Wells can be drilled quickly at an average cost of $300,000 to drill and tie-in, and typically capture 0.5 bcf of natural gas reserves. Production rates average 0.2 mmcf per day with the potential for decline rates of less than 10%, offering long-life reserves.

At Centron, following 1999 discoveries in the Edmonton and Belly River Formations, Compton conducted a 10-well development program in 2000. At Brant, Compton made a new discovery in the Basal Belly River Formation, and quickly delineated this pool by drilling a further nine wells. The Company also focused on establishing production infrastructure, bringing on production at Centron at 3 mmcf per day by year-end. Brant and Medallion production will be on production in the first half of 2001.

PALEOZOIC PLAYS

Compton intends to accelerate and maximize recovery of more than 100 bcf of recoverable Wabamun Formation sour gas reserves in the Okotoks-Mazeppa field, which on discovery in the 1950s had more than 700 bcf of gas-in-place. Production currently averages nearly 20 mmcf per day of raw gas at a relatively flat annual decline. In 2000, a major field review identified several candidates for re-entry and drilling of horizontal extensions to access better reservoir. By utilizing existing wellbores these horizontal step-outs, which could yield initial production rates of 5-10 mmcf per well, offer a low-cost means of increasing production and accelerating pool depletion at a time of high gas prices. There are also undrilled sections that could increase recoverable reserves. Population pressure from the southward expansion of the City of Calgary means there is an added social benefit to accelerating production of these reserves, which would otherwise produce for up to 70 years.

Additionally, Compton has Mississippian gas production from several pools throughout its core areas. A significant discovery was made in 2000 at Dalemead, east of Calgary, where the Company drilled three gas wells on a nine-section Elkton outlier acquired through farm-ins. Compton holds a 100% working interest before payout, reverting to 60% thereafter.

NEW EXPLORATION – TSUU T'INA AND STONEY

Compton has two exciting new plays developing to the north and west of its Southern Alberta core area. On the Tsuu T'ina Reserve, southwest of Calgary, the Company has access to 65 sections of land that remain very lightly explored due partly to their historical role as a military range. The area offers multiple objectives in both regional and structured Cretaceous sands at 1,200-2,600 metres depth. It is on-trend with recent discoveries by other producers to the north. Compton conducted a 2D seismic program late in 2000, and is committed to drill wells in the second half of 2001.

Compton has also entered the Foothills structural play with the acquisition of 10 sections at Stoney, northwest of Tsuu T'ina, that are prospective for Mississippian gas at 2,800-4,000 metres depth. The Company holds a 70% working interest and will operate the project. Compton's partner is an integrated producer that controls a key natural gas processing plant and has agreed to provide processing services for 10 years at reasonable cost. In 2000, Compton began generating prospects with a large 3D seismic survey. The Company is negotiating to add additional lands.

SOUTHERN ALBERTA 2001 PROGRAM

Southern Alberta will remain the focus of Compton's activities in 2001. The Company has built up a three-year inventory of exploration, development and exploitation prospects, and the region offers year-round access.

In Southern Alberta, Compton expects to drill more than 60 wells and to spend $70 million expanding its production volumes, facilities and land base in this multi-zone core area. Compton's program will continue to emphasize deeper, richer, low-decline reserves.

At Hooker, Compton is planning to drill 27 wells to continue development of the pool with the aid of a 65-square-mile 3D seismic program. Seismic will be acquired on lands purchased in late 2000 and four exploratory wells will be drilled on the Basal Quartz trend south of Hooker.

On the shallow gas trend, Compton will tie-in remaining wells and plans to drill a further 24 wells.

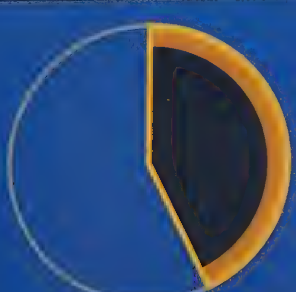
Compton will launch its Okotoks horizontal development program in 2001 by re-entering two to four wells, stimulating production and enhancing recoveries.

At Dalemead, infrastructure development is expected to allow the three natural gas discoveries to be tied in and Compton has plans for three to five further wells on the play in 2001.

Two wildcats are planned for the Tsuu T'ina lands in 2001, following interpretation of the seismic program shot late in 2000. At Stoney, the Company expects to complete its 3D seismic interpretation in the second quarter of 2001. Drilling approvals for foothills sour gas wells may require considerable lead-time due to the necessity for public consultation. Compton hopes to spud its first Stoney well in late 2001.

Compression installation at Hooker, Centron, Brant, and at the Mazeppa Plant inlet are planned for 2001. This infrastructure will maximize well delivery.

% SOUTHERN ALBERTA



43%
TOTAL UNDEVELOPED LAND

43%
TOTAL 2000 PRODUCTION

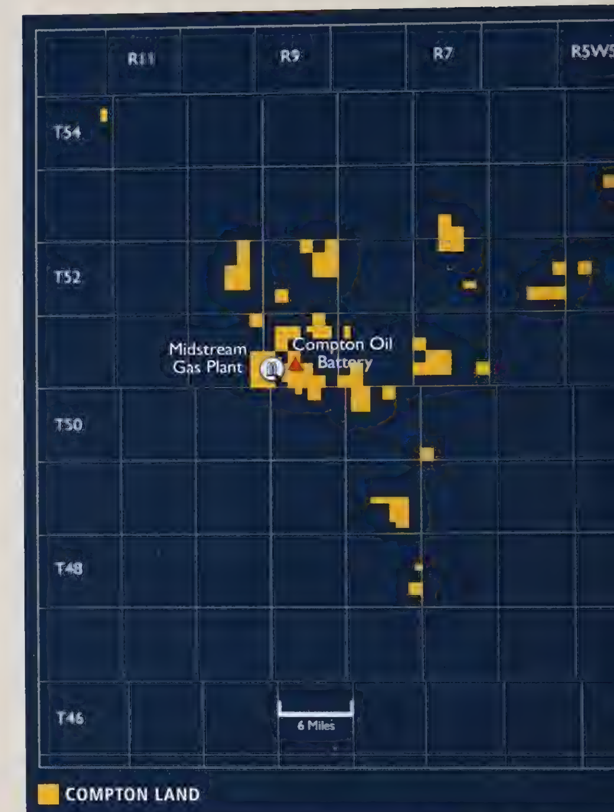
63%
TOTAL 2001 CAPITAL EXPENDITURES

WEST CENTRAL ALBERTA – Bigoray

The Bigoray properties were Compton's first significant entry into crude oil production, through the purchase of J.M. Huber in December 1998. Compton operates the Cardium 'B' pool as well as having interests in three deeper Nisku reef pools. Compton's focus is on enhancing light oil production to provide cash flow needed to fund other growth activities.

Compton drilled six wells in the Cardium 'B' pool in 2000. Four were successful oil producers in the Cardium objective and two were Belly River gas wells. Compton will drill at least two wells in 2001 and continue pressure support through waterflooding, completing development of this pool.

The area offers exploration potential for lower Mannville gas. In 2000, Compton's exploration team made a gas discovery in the Ostracod zone that was completed at 3.5 mmcf per day of gas plus 110 bbls per day of condensate. Technical work will continue in 2001 to identify Cretaceous Ostracod and Glauconitic prospects. Compton will continue to expand in the area through acquisition and exploration opportunities.



% WEST CENTRAL ALBERTA

19%
TOTAL UNDEVELOPED LAND

37%
TOTAL 2000 PRODUCTION

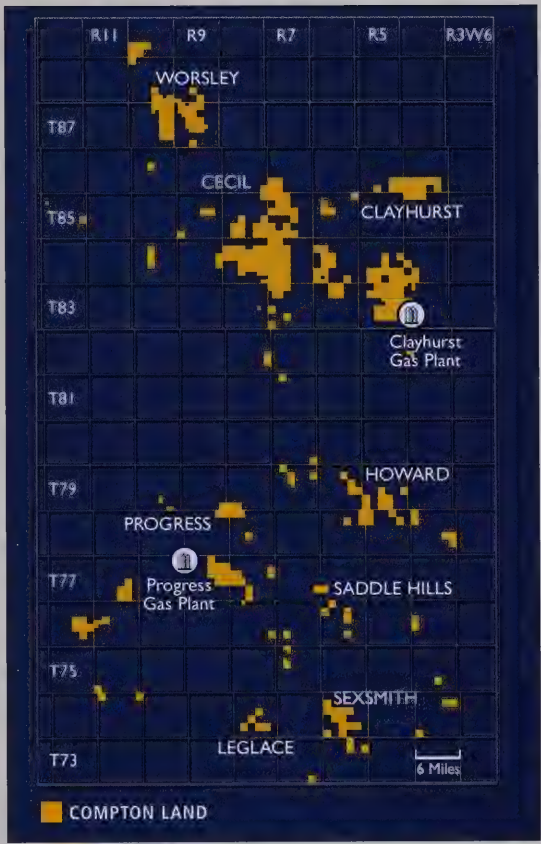
21%
TOTAL 2001 CAPITAL EXPENDITURES

Peace River ARCH

Compton acquired a significant land interest, operatorship and infrastructure on the Peace River Arch through its Huber and Coparex acquisitions in 1998 and 1999. The area offers a range of opportunities from low-risk exploitation, to secondary recovery efforts, to pure exploration. This range of opportunities prompted Compton to expand its technical team to generate prospects in the area. Compton was further encouraged by an oil discovery in 2000 in the Kiskatinaw Formation at Cecil.

In the Cecil area, several oil pools held at high working interest are potential candidates for horizontal and vertical infill drilling down to 40 acre spacing, and for waterflooding to increase recoveries. In the Worsley oil pool (91% working interest). Compton plans to implement a pilot waterflood in 2001 and to increase recovery through workovers and recompletion opportunities. Compton also sees potential to extend the Worsley pool through infill drilling. A seismic program is planned for Clayhurst, where Compton holds a large land block and a natural gas processing plant, targeting Mississippian, Triassic and Cretaceous objectives.

Compton's strategy in this relatively new core area is to become a dominant player, similar to the Company's strategy for Southern Alberta.



% PEACE RIVER ARCH

17%
TOTAL UNDEVELOPED LAND

19%
TOTAL 2000 PRODUCTION

13%
TOTAL 2001 CAPITAL EXPENDITURES

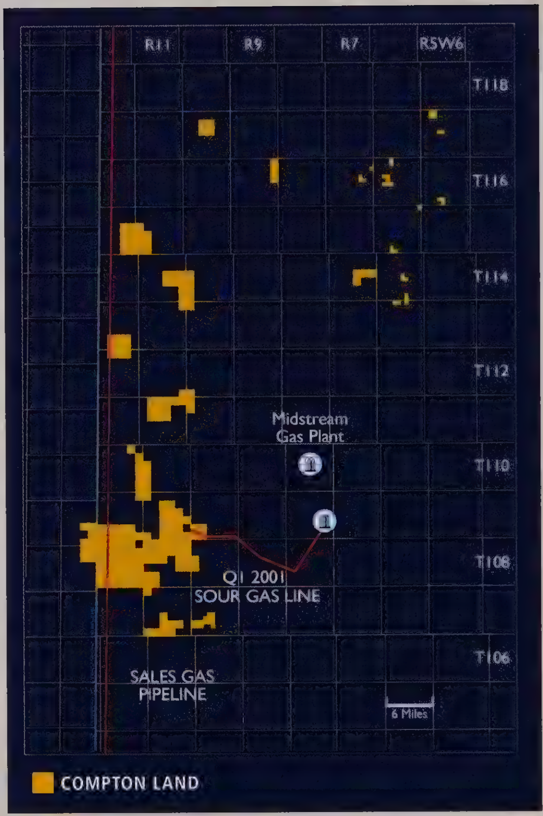
NORTHERN ALBERTA – West Rainbow

The Rainbow area of northwest Alberta has long been recognized as having "trapped gas" due to the lack of infrastructure. It remains one of the most under-explored natural gas regions in Alberta. The recent construction in 1998 of a Nova sales gas pipeline running along the Alberta-British Columbia border and directly through Compton's land has accelerated interest in gas exploration at Rainbow.

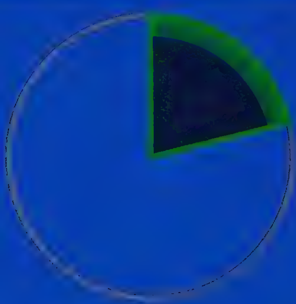
Compton sees two levels of opportunity. In the Rainbow and Zama basins, there are uphole gas prospects in the Slave Point and Sulphur Point formations overlying the Devonian oil pools. The Company has a modest exploitation position on this play, and in 2001 plans to recomplete two to three Devonian Slave Point and Sulphur Point wells.

More exciting for the longer term are wildcat natural gas opportunities in several formations to the west of the traditional oil area, where Compton holds nearly 200 sections of land at West Rainbow. During 2000, Compton tested three play concepts in zones ranging from the Devonian to the Tertiary, resulting in one Bluesky gas discovery. Two earlier gas discoveries remain shut-in.

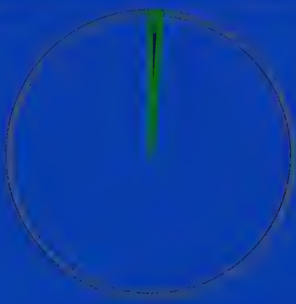
During 2001, Compton will acquire seismic data to delineate these plays and will drill two wells. The winter-only access area remains in an early stage of exploration, but development will accelerate quickly with positive drilling results and infrastructure development.



% NORTHERN ALBERTA



21%
TOTAL UNDEVELOPED LAND



1%
TOTAL 2000 PRODUCTION

3%
TOTAL 2001 CAPITAL EXPENDITURES

ENGINEERING AND OPERATIONS Review

PRODUCTION

In 2000, Compton's average annual production was 14,812 boe per day (10:1), and 20,488 boe per day (6:1), representing an increase of 37% over 1999's annual average production. The 2000 natural gas, crude oil and natural gas liquids average production rates were: 85.1 mmcf per day, 4,408 bbls per day and 1,897 bbls per day, compared to 1999 averages of 63.7 mmcf per day, 2,756 bbls per day and 1,718 bbls per day.

AVERAGE PRODUCTION RATES

	1995	1996	1997	1998	1999	**2000**
Oil (bbls/d)	–	158	191	223	2,756	**4,408**
Gas (mmcf/d)	0.4	4.7	16.2	33.1	63.7	**85.1**
NGLs (bbls/d)	37	87	300	611	1,718	**1,897**
boe/d (10:1)	71	713	2,113	4,146	10,844	**14,812**
boe/d (6:1)	**95**	**1,025**	**3,194**	**6,351**	**15,091**	**20,488**

RESERVES

Compton's established reserves net of 5.4 mmboe of production, increased by 14% from 44.5 mmboe in 1999 to 50.5 mmboe in 2000. This gain was accomplished at a finding and onstream cost of $7.10 per boe for established reserves (6:1) and at $10.42 per established boe (10:1). Compton's proven reserves represent 83% of established reserves. The year-end reserves are equivalent to one-half trillion cubic feet equivalent.

Compton's Jan 1, 2001 reserves as determined by the independent engineering firm Outtrim Szabo and Associates are as follows:

RESERVE VALUE – ESCALATED DOLLAR ECONOMICS

At December 31, 2000	OIL MBBL	GAS BCF	NGLS MBBL	TOTAL MBOE 10:1	TOTAL MBOE 6:1	DCF VALUE 15% $000s	DCF VALUE **10% $000s**
Reserve Category:							
Proven producing	7,064.4	191.2	2,707.8	28,889.9	41,635.0	341,540	**426,852**
Proven non-producing	992.7	52.1	822.7	7,020.8	10,491.2	90,291	**114,376**
Proven undeveloped	445.8	46.0	772.9	5,820.4	8,888.0	37,759	**57,556**
Total proven	8,502.9	289.3	4,303.4	41,731.2	61,014.2	469,590	**598,784**
Probable, risked	2,864.2	48.2	1,048.3	8,742.0	11,961.8	51,090	**80,063**
Established	**11,367.1**	**337.5**	**5,351.7**	**50,473.2**	**72,976.0**	**520,680**	**678,847**

Refer to page 36 in the Management's Discussion & Analysis for pricing forecast assumptions used.

CONSTANT DOLLAR ECONOMICS

At December 31, 2000	DCF VALUE 15% ($000s)	DCF VALUE 10% ($000s)
Reserve Category:		
Proven producing	708,416	**830,919**
Proven non-producing	205,000	**240,205**
Proven undeveloped	125,546	**156,319**
Total proven	1,038,962	**1,227,443**
Probable, risked	141,801	**181,855**
Established	**1,180,763**	**1,409,299**

For the Company's constant dollar pricing evaluation, petroleum and natural gas reserves are based upon commodity price assumptions as at January 1, 2001. They reflect a bbl of oil price of Cdn.$39.33, a natural gas price of Cdn.$9.69 per mcf, and a natural gas liquids price of Cdn.$37.57 per bbl.

RESERVE RECONCILIATION

	CRUDE OIL & NGLs			NATURAL GAS			
	PROVED MBBL	50% PROB MBBL	TOTAL MBBL	PROVED BCF	50% PROB BCF	TOTAL BCF	TOTAL MBOE (10:1)
December 31, 1999	13,115.6	2,498.7	15,614.4	250.3	38.7	289.0	44,512.7
Development, exploration and exploitation	1,200.2	675.6	1,875.7	71.3	8.2	79.5	9,826.0
Acquisitions, net	1,567.1	451.2	2,018.3	(1.6)	(1.4)	(3.0)	1,722.9
Reserve revisions	(775.2)	287.0	(488.2)	0.3	2.8	3.1	(181.9)
Production	(2,301.3)	–	(2,301.3)	(31.1)	–	(31.1)	(5,406.5)
December 31, 2000	**12,806.4**	**3,912.4**	**16,718.9**	**289.2**	**48.3**	**337.5**	**50,473.2**

Compton has a unique reserve makeup as 65% of its corporate reserves are assigned to reservoirs with a depth in excess of 2,100 metres. This translates into longer reserve life and less steep decline curves. Using the 2000 average production rate of 14,812 boe per day on a 10:1 basis, the reserve life index is approximately 10 years for established reserves.

OPERATIONS AND FACILITIES

The majority of Compton's existing production comes from three main core areas: High River/Okotoks in Southern Alberta, Bigoray in West Central Alberta and the Peace River Arch.

In High River and Okotoks, Compton concentrated its efforts on the Hooker Basal Quartz deep gas development where 18 wells were drilled during 2000. The year-end 2000 exit rate from Hooker was 25 mmcfe per day net to Compton with 83 bcfe net established reserves booked. This met the internal target that was set for the Hooker project. At the beginning of the year the Hooker pipeline capacity was 8 mmcf per day. By August 2000, the pipeline and compression infrastructure capacity was increased to 35 mmcf per day and plans are underway to expand this takeaway capacity to 45 mmcf per day by mid-year 2001.

Compton also drilled 10 shallow Belly River gas wells in the Centron field immediately east of Calgary. In this play Compton achieved 100% drilling success. At Centron, Compton placed a 100% owned gas plant on continuous production. At year-end 2000 this gas facility was producing 3 mmcf per day of gas from 15 shallow gas wells. In 2001, Compton plans to tie in five existing gas wells and infill drill this project on 320-acre spacing as opposed to the existing 640-acre spacing.

In 2000, a similar shallow gas program was pursued at Brant, just east of High River, with the drilling of 10 wells. Compton constructed a gas compressor station and 15 miles of gathering system at Brant in which the Company has a 50% ownership. This system offers a unique competitive advantage for developing offset shallow gas lands. The system has a four township capture area and is the only gas gathering alternative in this newly developing gas play. In 2001, Compton plans to tie in existing Brant gas wells and drill as many as an additional 15 wells. Similar to the Centron project, Brant will be infill drilled with reduced spacing to accelerate depletion.

At the Clayhurst gas plant located in the Peace River Arch, Compton installed an amine unit, which allows Compton to process sour gas. The plant capacity of 10 mmcf per day is approximately 50% loaded, with plans to aggressively drill in the area and expand to 22 mmcf per day.

DRILLING AND COMPLETIONS

In 2000, Compton drilled a total of 96 wells with an average well depth of approximately 1,730 metres. Compton has experienced and dedicated operations personnel who are drilling, completing and operating deep wells in a safe and cost-effective manner. The Company maintains a competitive advantage through its expertise in drilling, completing and operating deep, sour and sweet natural gas wells.

DRILLING ACTIVITY

AREA	GAS	OIL	D&A	TOTAL	NET
Southern Alberta	40	2	12	54	44.0
Central Alberta	11	5	6	22	19.8
Northern Alberta	5	3	12	20	14.5
Total	**56**	**10**	**30**	**96**	**78.3**

MARKETING

Compton's average 2000 field prices in Canadian funds were $4.55 per mcf of natural gas, $33.92 per bbl of oil and $25.19 per bbl of natural gas liquids. This compares to the 1999 prices of $2.63 per mcf, $25.49 per bbl and $16.32 per bbl, respectively. In 2000, aggregators marketed 39% of Compton's gas and non-contracted gas indexed to AECO pricing represented 61%. This compares to 40% aggregator and 60% non-contracted volumes in 1999. The shift towards non-aggregator volumes year-over-year represents a conscious effort to develop the Company's higher value non-dedicated lands first. Non-contracted gas volumes are being managed on a competitive annual quote basis.

OPERATING COSTS

Operating costs increased to $5.82 per boe (10:1) from $5.18 per boe (10:1) when comparing 2000 to 1999. This 12% increase reflects the degree of sour gas in Compton's produced gas volumes as well as increases to field compression. The increase also reflects the amount of new gas being placed onstream and the higher operating costs associated with the early stage of new projects. We are working hard to continually reduce operating costs, including maximizing ownership of compression and pipelines wherever possible. Compton is committed to maintaining efficient and low cost operations.

COMMUNITY AFFAIRS, ENVIRONMENT AND SAFETY

Compton is committed to conducting all operations, including drilling, completions and workovers, construction and daily operations in a safe manner to ensure that the safety and health of employees, contractors and community residents are protected. The Company is pledged to operating in an environmentally safe manner. Compton complies with all current government and regulatory legislation and is staffed to manage continual regulatory changes.

FUTURE GROWTH

The production growth since the Company went public on The Toronto Stock Exchange in the fall of 1996 has shown a significant gain from 77 boe per day to 14,812 boe per day (10:1). Compton has accomplished this increase through strategic planning, teamwork and execution by dedicated personnel. The Company has the necessary technical personnel to manage the 120 well drilling program planned for 2001 and to manage existing production. Our continued corporate focus is disciplined, internally-generated growth.

MANAGEMENT'S DISCUSSION & Analysis

MANAGEMENT'S Discussion and Analysis is a review of the Company's 2000 financial and operating results and should be read in conjunction with the financial statements and related notes. The discussion is intended to provide both a historical and prospective view of the Company's activities.

CORPORATE FOCUS

Compton's operating and financial results are directly influenced by the Company's financial discipline and overall strategy for creating shareholder value through profitable, long-term sustained growth. In 2000, the Company's operations were focused on all aspects of full-cycle exploration. Compton is committed to profitable, sustainable growth through focusing on long-life natural gas reserves with a balanced risk portfolio of inventory prospects.

DRILLING

Compton drilled 96 (78 net) wells in 2000, an increase of 16% from the 83 (71 net) wells in 1999, a new Company record. The program was heavily exploration-weighted, with 53 gross wells classified as exploratory or outpost. Compton's focus on longer-life, lower-decline reserves resulted in an average drilling depth of 1,730 metres. The program included 33 deep tests. The Company attained an overall drilling success rate of 70%, and 85% of successful wells were natural gas wells. Compton is maintaining an aggressive, balanced-risk drilling program for 2001, with approximately 120 wells budgeted.

EXPANSION

During 2000, Compton expanded its land position in all of its core areas. The Company incurred land acquisition expenditures of approximately $15 million, which resulted in the addition of 106,016 net acres of undeveloped land. Of this amount, $8 million was spent to augment and extend the Company's holdings along the Hooker trend in Southern Alberta.

FINANCIAL/OPERATING HIGHLIGHTS

YEAR ENDED DECEMBER 31	2000		1999		1998	
OPERATIONS						
Average production						
Natural gas (mmcf/d)		**85.1**		63.7		33.1
NGLs (bbls/d)		**1,897**		1,718		611
Oil (bbls/d)		**4,408**		2,756		223
Boe/d (10:1)		**14,812**		10,844		4,146
Boe/d (6:1)		**20,488**		15,091		6,351
Three year average F & D costs						
per boe (10:1)		**$ 7.81**		$ 6.92		$ 5.23
per boe (6:1)		**$ 5.57**		$ 4.82		$ 3.41
FINANCIAL	**$000s**	**Per BOE**	$000s	Per BOE	$000s	Per BOE
Revenue, net	**$ 168,681**	**$ 31.11**	$ 80,911	$ 20.44	$ 27,756	$ 18.34
Expenses						
Operating	**(31,571)**	**(5.82)**	(20,521)	(5.18)	(7,477)	(4.94)
General and administrative	**(5,915)**	**(1.09)**	(4,222)	(1.07)	(1,517)	(1.00)
Interest	**(12,772)**	**(2.36)**	(6,939)	(1.75)	(1,023)	(0.68)
Capital taxes	**(890)**	**(0.16)**	(199)	(0.05)	(202)	(0.13)
Cash flow from operations	**$ 117,533**	**$ 21.68**	$ 49,030	$ 12.39	$ 17,537	$ 11.59
Depletion and depreciation	**(41,767)**	**(7.70)**	(20,160)	(5.09)	(6,671)	(4.41)
Income taxes, future	**(35,707)**	**(6.57)**	(11,782)	(2.98)	(4,262)	(2.81)
Net earnings	**$ 40,059**	**$ 7.41**	$ 17,088	$ 4.32	$ 6,604	$ 4.37
Per share amounts						
Cash flow, basic	**$ 1.10**		$ 0.50		$ 0.20	
Cash flow, diluted	**$ 1.06**		$ 0.49		$ 0.19	
Earnings, basic	**$ 0.37**		$ 0.18		$ 0.07	
Earnings, diluted	**$ 0.36**		$ 0.17		$ 0.06	
Return on Net Revenue	**23.7%**		21.1%		23.8%	
Return on Equity*	**34.0%**		17.2%		8.8%	

* Return on Equity is calculated as the percentage current net earnings is of year end shareholders' equity less current year net earnings.

RESULTS OF OPERATIONS

REVENUE

Revenue, before royalties, totalled $213.4 million in 2000, an increase of 120% from $97.1 million in 1999. This gain was attributable to a combination of higher production volumes of all commodities, which accounted for 31% of the increase, and much stronger realized commodity prices, which accounted for the remaining 69% of the increase.

West Texas Intermediate crude averaged US$30.26 per bbl during the year, as compared to US$19.32 per bbl in 1999. Natural gas prices were also very robust. The Alberta spot price averaged $5.55 per mcf last year, compared to $2.93 per mcf in 1999. Prices realized by Compton during the year are provided within the Netbacks section.

During 2000, approximately 39% of Compton's natural gas production was committed to aggregators and received a price lower than AECO. Prior to 2000, the Company did not have a hedging program in place and all production was sold through aggregators or on spot. With the acquisition of Coparex Canada Ltd. in December of 1999, Compton instituted a hedging program to ensure the year 2000 budgeted cash flow from the production acquired. For 2000, the Company had hedged 549,000 bbls of oil at a price of US$21.75 per bbl. The Company's average crude oil price of $33.92 per bbl, realized for the year, is net of a hedging opportunity cost of $13.94 per bbl relating to 549,000 bbls of production hedged. Additionally, 7.1 mmcf per day of natural gas was sold pursuant to contracts at an average price of $3.55 per mcf, for the period from January 1, 2000 to October 31, 2000.

Currently, for 2001, the Company has none of its oil production hedged. On the natural gas side, the Company has contracted 9.5 mmcf per day of gas from November 1, 2000 through March 31, 2001, under a costless collar arrangement, having a floor of $5.80 per mcf and a ceiling of $9.54 per mcf. Additionally, 5.7 mmcf per day is contracted from April 1, 2001 through to October 31, 2001, under a costless collar arrangement, having a floor price of $6.85 per mcf and a ceiling of $8.63 per mcf.

Revenue by commodity is provided in the table below.

REVENUE

YEAR ENDED DECEMBER 31	**2000**	1999	1998
($000s)			
Natural gas	**$ 141,368**	$ 61,135	$ 25,320
Oil	**54,569**	25,649	1,355
NGLs	**17,439**	10,232	3,870
Total	**$ 213,376**	$ 97,016	$ 30,545

ROYALTIES

Royalties, before royalty credits, increased in 2000 to a total of $46.9 million, up by 135% from $20.0 million in 1999. This increase is attributable to a combination of higher production volumes, and the effects of the provincial sliding-scale royalty structure, which imposes higher royalty rates at higher product prices. Compton's average royalty rate on its combined production was 22.0% in 2000, compared to 20.6% in 1999.

Royalty credits, (Alberta Royalty Tax Credits – ARTC, Gas Cost Allowance and Custom Processing Credits) decreased to $2.2 million in 2000 from $3.9 million in 1999. The credits decreased as a percentage of royalties to 4.8% in 2000 from 19.5% in 1999. This decrease was primarily driven by the favourable gas price environment in 2000, which resulted in a lower ARTC entitlement compared to prior years.

Based on the Company's price forecasts for 2001, Compton expects its average royalty rate before credits to be relatively unchanged from 2000, approximating 22% in 2001.

OPERATING COSTS

Operating costs increased to $31.6 million in 2000 from $20.5 million in 1999, largely as a result of increases in Compton's production volumes. On a boe basis, operating costs increased to $5.82, an increase of 12% from the $5.18 per boe realized in 1999. The increase in unit cost is attributable to higher initial costs associated with new production, and to general increases in costs of goods and services associated with the industry's high level of field activity.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased to $5.9 million in 2000 from $4.2 million in 1999. This increase of 40% is almost entirely attributable to higher levels of staffing commensurate with the Company's increased level of activity. On a boe basis, general and administrative costs were $1.09, a marginal increase of 2% from $1.07 in 1999. As of December 31, 2000, Compton had 60 office employees, compared to 51 office employees at year-end 1999.

Compton does not capitalize overhead costs except for salary costs directly attributable to full-cycle exploration activities. These capitalized costs totalled $2.0 million in 2000, an increase from $1.5 million in 1999, reflecting Compton's increased exploration and development activities. Notwithstanding the higher level of full-cycle exploration activity in 2000, the Company continued to maintain overhead efficiency as evidenced by the table provided below:

OVERHEAD EFFICIENCY

	2000	1999
Office employees at year end	**60**	51
Production per employee (boe/d)	**247**	212
Cash flow per employee ($000)	**1,958**	961
Expense per boe produced ($) (10:1)	**1.09**	1.07
Expense per boe produced ($) (6:1)	**0.79**	0.77

INTEREST EXPENSE

During 2000, Compton experienced an interest rate of approximately 7% on its average outstanding bank debt, resulting in total interest expense of $12.8 million, up from $6.9 million in 1999. Compton's cash-flow-to-interest coverage was 9.2 times in 2000, an improvement from 7.1 times in 1999 and attributable to much stronger cash flow.

DEPLETION, DEPRECIATION AND AMORTIZATION

Compton's depletion, depreciation and amortization expenses, which include a provision for the future costs of abandonment and restoration, increased to $41.8 million in 2000 from $20.2 million in 1999. On a boe basis, depletion, depreciation and amortization amounted to $7.70 per boe in 2000, compared to $5.09 per boe in 1999. A change in accounting policy to account for future income taxes payable resulted in an increase in the carrying value of assets of $68.1 million, and in turn generated an incremental increase in the annual depletion and depreciation rate of approximately $1.40 per boe.

CEILING TEST

In accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines, the Company performs an annual ceiling test calculation, whereby the net book value of the Company's oil and gas properties is compared to the estimated future realizable value of its proven reserves. Reserves are valued based upon year-end constant dollar pricing. Prices used for the calculation at December 31, 2000 were CDN$9.69 per mcf of natural gas, CDN$39.33 per bbl of crude oil, and CDN$37.57 per bbl of natural gas liquids.

At December 31, 2000, the estimated realizable future value of proven reserves, so calculated, exceeded the book value of oil and gas properties by approximately $1 billion. The calculation in 1999 resulted in an excess of approximately $165 million over the book value.

INCOME TAXES

Compton's provision for future income taxes totalled $35.7 million in 2000. This compared to $11.8 million in 1999, and brought Compton's effective rate of income tax to 47.7% in 2000. The Large Corporation capital tax increased to $890,000 from $199,000 one year ago, due to the Company's increased capitalization during the year.

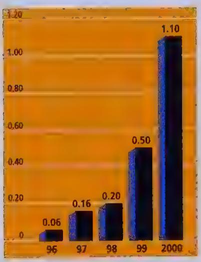
Effective January 1, 2000, the Company adopted the new recommendations of the Canadian Institute of Chartered Accountants with respect to accounting for future income taxes. Under the new recommendations the liability method of tax allocation is used, which is based upon the difference between financial and tax bases of assets and liabilities. Previously, the deferred method was used which was based upon differences between the timing of reporting income and expenses for financial and income tax purposes.

The Company has adopted this change in accounting policy retroactively, without restating the financial statements of prior periods. As a result, the Company recorded a reduction in retained earnings of $0.4 million, an increase in property and equipment of $68.1 million, and an increase in the future income tax liability, previously the deferred income tax liability of $68.5 million, as at January 1, 2000. The adjustments were mainly the result of future tax costs relating to acquisitions where the tax base acquired was less than the purchase price, and the tax consequence of flow-through share issues.

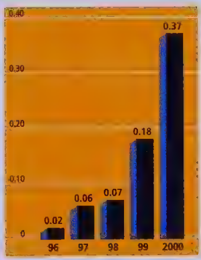
CASH FLOW AND NET EARNINGS

Compton generated cash flow from operations of $117.5 million in 2000 ($1.10 per share), an increase of 140% from $49 million in 1999 ($0.50 per share). Net earnings totalled $40.1 million ($0.37 per share), an increase of 134% from $17.1 million ($0.18 per share) in 1999. This was the sixth consecutive year in which Compton delivered increases in cash flow and net income.

CASH FLOW
($/share)



NET EARNINGS
($/share)



NETBACKS

The field cash netback, defined as sales revenue less royalties and operating costs, is a key indicator of an Exploration and Production (E&P) company's ability to generate cash flow available for reinvestment, and accordingly is an indicator of the Company's ability to sustain profitable growth. In 2000, Compton generated an overall cash netback of $25.29 per boe (10:1), an increase of 66% from $15.21 per boe (10:1) in 1999.

NETBACKS

YEAR ENDED DECEMBER 31	**2000**			1999			1998		
	NATURAL GAS $/MCF	**OIL & LIQUIDS $/BBL**	**TOTAL $/BOE**	NATURAL GAS $/MCF	OIL & LIQUIDS $/BBL	TOTAL $/BOE	NATURAL GAS $/MCF	OIL & LIQUIDS $/BBL	TOTAL $/BOE
Revenue	**$4.55**	**$31.29**	**$39.38**	$2.63	$21.97	$24.51	$2.00	$17.16	$19.40
Royalties, net	**(0.89)**	**(7.38)**	**(8.27)**	(0.37)	(4.77)	(4.12)	(0.15)	(3.05)	(1.85)
Operating costs	**(0.58)**	**(5.85)**	**(5.82)**	(0.58)	(4.31)	(5.18)	(0.55)	(2.86)	(4.94)
Netback	**$3.08**	**$18.06**	**$25.29**	$1.68	$12.89	$15.21	$1.30	$11.25	$12.61

CAPITAL EXPENDITURES

Net capital expenditures totalled $118.5 million in 2000, as compared to $130.5 million in 1999. Year 2000 capital expenditures reflect Compton's strategy for long-term growth. The Company invested heavily in undeveloped land acreage, seismic, production facilities and exploration drilling necessary for continued value creation. Exploratory drilling and completion expenses totalled approximately $43 million in 2000, 64% of the total $67 million expended on exploration, exploitation and development. During the year, the Company's drilling program succeeded in adding 9.8 million boe (10:1) of reserves on an established basis.

The table below sets out Compton's capital expenditures by category over the past three years.

CAPITAL EXPENDITURES

	2000		1999		1998	
	($000s)	**%**	($000s)	%	($000s)	%
Property, lease and seismic expenditures	**$ 23,241**	**19.6**	$ 12,859	9.9	$ 8,092	11.6
Exploration, development and exploitation	**66,695**	**56.4**	45,359	34.8	23,831	34.1
Production equipment and facilities	**27,901**	**24.0**	12,090	9.3	7,686	11.0
Other	**317**	**–**	908	0.1	511	0.1
Acquisitions (dispositions), net	**318**	**–**	(15,351)	(11.8)	(61,613)	(88.1)
	$ 118,472	**100.0**	$ 55,865	42.8	$ (21,493)	(30.8)
Corporate acquisitions	**–**	**–**	74,594	57.2	91,394	130.8
Total, net	**$ 118,472**	**100.0**	$ 130,459	100.0	$ 69,901	100.0

FINDING AND DEVELOPMENT COSTS

Finding and development (F&D) costs are the all-in costs of adding new reserves, and include the costs of undeveloped land, seismic, drilling, completion, tie-in and construction of field facilities. F&D costs are an important measure of an E&P company's ability to sustain profitable growth. During 2000, Compton's F&D cost on an established reserve basis, was $10.42 per boe at a (10:1), and $7.10 per boe (6:1). This compares to $8.96 per boe (10:1) and $6.62 per boe (6:1) in 1999. This increase in 2000 is partially attributable to higher field costs as a result of the increased industry activity, but is mainly due to the 2000 capital program that was skewed proportionately higher to upfront capital activities, such as land and seismic spending, with such investments generating reserves in the future. The Company's 2000 F&D cost is within the mid-range of the Company's peer group. Compton's three-year average F&D cost is $7.81 per boe (10:1) and $5.57 per boe (6:1). The Company's five-year average F&D cost is $6.83 per boe (10:1) and $4.79 per boe (6:1).

RECYCLE RATIO

The recycle ratio is used as an indicator of the efficiency with which an E&P company can replace its produced reserves. As such, the recycle ratio is widely accepted as a measure of value creation. In 2000, Compton generated a recycle ratio of 2.4 times. This brought the Company's three-year average recycle ratio to 2.3 times. Each boe produces a cash netback more than twice the cost of replacing that boe.

RETURN ON EQUITY

Return on equity measures whether a company is investing its shareholders' capital efficiently and effectively, and also serves as an indicator of a company's potential to appreciate in the capital markets. In 2000, Compton generated a return on shareholders' equity of 34.0%, compared to a return of 17.2% in 1999. This marked the fifth consecutive year of an increased rate of return.

LIQUIDITY AND CAPITAL RESOURCES

Compton is committed to maintaining a strong balance sheet to minimize vulnerability to unforeseen declines in commodity prices as well as to maximize the Company's ability to respond to opportunities for strategic acquisitions as they arise. At year-end 2000, Compton's debt net of working capital totalled $153.6 million, down from year-end 1999 of $158.6 million. The year-end figure includes the effect of paying down $15 million of subordinated debt in April 2000. In keeping with Compton's policy of maintaining a debt-to-cash-flow ratio of less than 2:1, the Company's year-end debt represented 1.0 times annualized fourth quarter 2000 cash flow and1.3 times year 2000 cash flow.

Under the Company's current pricing assumptions, Compton expects cash flow to exceed existing budgeted capital expenditures in 2001. The projected surplus will provide the Company flexibility with which to reduce bank debt, extend the Company's normal course issuer bid, increase the capital expenditures budget, and to undertake a strategic acquisition if the opportunity arises. Compton currently has no plans to issue new equity in 2001.

NORMAL COURSE ISSUER BID

In February 2001, Compton obtained regulatory approval to renew its normal course issuer bid to acquire an aggregate amount of up to approximately 5.4 million common shares in the capital of the Company.

The acquisition of common shares through the normal course issuer bid will occur over a period of 12 months, commencing March 5, 2001 and ending on March 4, 2002 (unless terminated earlier by the Company). Compton intends to acquire the common shares at prices that represent a discount to the underlying net asset value. After the shares are acquired, they will be cancelled by the Company. The purpose of the acquisition and cancellation of the shares is to provide capital appreciation and market stability for the benefit of Compton's shareholders.

NET ASSET VALUE

Compton has determined a net asset value as at December 31, 2000 based upon established reserves (escalated dollar pricing) discounted at 10% and 15% as calculated below.

NET ASSET VALUE

AT DECEMBER 31, 2000 ($ MILLIONS)	10% DCF	15% DCF
Petroleum and natural gas reserves	$ 678.8	$ 520.7
Undeveloped land	78.0	78.0
Seismic and other	20.4	20.4
Other	1.6	1.6
	$ 778.8	$ 620.7
Corporate debt, net	(153.6)	(153.6)
Net asset value	**$ 625.2**	**$ 467.1**
Common shares (000s)	108,784	108,784
Net asset value per share	**$ 5.75**	**$ 4.29**

Petroleum and natural gas reserves are based upon commodity price assumptions as at January 1, 2001 and reflect a per barrel oil price (Edmonton Light) of CDN$40.74 for 2001, decreasing to CDN$31.33 by 2003, and escalating after 2009 at an average annual rate of 1.5% per year through 2020. Natural gas pricing is based upon AECO-C Spot of CDN$7.50 per mcf for 2001, decreasing to CDN$4.07 per mcf by 2007, and escalating thereafter at an average annual rate of 1.5% through 2020.

BUSINESS CONDITIONS, RISKS AND RISK MITIGATION

Compton's operations are subject to risks normally associated with the oil and natural gas industry. The most important of these are set out below, with the strategies Compton employs to mitigate and minimize these risks outlined:

- Inherent industry risk that exploration and development programs undertaken will result in economic reserve additions to replace production.

Compton's strategies to minimize this inherent risk include focusing on selected areas in western Canada, utilizing a team of highly qualified professionals with expertise and experience in these areas, expanding operations in core areas, continuously assessing strategic acquisitions to complement existing activities and striving for a balance between exploration and lower-risk development and exploitation prospects.

- Commodity prices and expenditure costs shift due to changes in market conditions.

Commodity prices are driven by supply, demand and market forces outside the Company's influence. Compton monitors and focuses its expenditures to reflect price and production changes. Compton continuously monitors market conditions and opportunities. From time to time the Company will employ financial instruments to manage exposure related to Canada/U.S. exchange rates and commodity prices. At December 31, 2000 the Company had commodity and fixed-price contracts outstanding as outlined in Note 13 to the financial statements. The Company considers longer-term contracts with suppliers, where appropriate, to mitigate such changes. Additionally, Compton has no control over government intervention or taxation levels on the industry.

- Mechanical and operational risks associated with the drilling for, production and processing of natural gas and crude oil, including damage to the Company's equipment and the liability associated with an occurrence or malfunction.

Compton manages operational risks by employing skilled professionals utilizing leading-edge technology and conducting regular maintenance and training programs. The Company has both an operational emergency response plan and an operational safety manual. In addition, a comprehensive insurance program is maintained to mitigate risks and protect against significant losses.

- Environmental risk and impact resulting from the Company's field operations.

Compton operates in accordance with all environmental legislation. The Company strives to maintain and surpass compliance with such regulations and works with government agencies, landholders and other parties to minimize the environmental impact of its activities.

MANAGEMENT'S Report

The accompanying financial statements of Compton Petroleum Corporation and all other financial and operating information contained in this Annual Report are the responsibility of management. The financial statements have been prepared in accordance with accounting policies detailed in the notes to the financial statements and in accordance with generally accepted accounting principles in Canada.

The Company's systems of internal control have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial records are sufficiently well maintained to provide relevant, timely and reliable information to management.

External auditors, appointed by the shareholders, have independently examined the financial statements. They have performed such tests as they deemed necessary to enable them to express an opinion on these financial statements.

An Audit Committee of the Board of Directors has reviewed these financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

E.G. Sapieha, C.A.
President and
Chief Executive Officer

N.G. Knecht, C.A.
Vice President, Finance and
Chief Financial Officer

AUDITORS' Report

To the Shareholders of Compton Petroleum Corporation

We have audited the balance sheets of Compton Petroleum Corporation as at December 31, 2000 and 1999 and the statements of earnings and retained earnings and statements of cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and cash flow for the years then ended in accordance with generally accepted accounting principles.

Calgary, Alberta
March 2, 2001

Grant Thornton LLP
Chartered Accountants

BALANCE SHEETS

DECEMBER 31 ($000s)	2000	1999	1998
ASSETS			
Current			
Accounts receivable and other	$ 81,225	$ 32,787	$ 25,433
Assets held for sale (Note 4)	–	18,870	–
	81,225	51,657	25,433
Notes receivable (Note 5)	150	150	150
Property and equipment (Note 6)	442,897	297,560	186,500
	$ 524,272	$ 349,367	$ 212,083
LIABILITIES			
Current			
Current bank debt (Note 7)	$ –	$ 15,060	$ –
Accounts payable and accruals	51,439	35,524	25,126
	51,439	50,584	25,126
Long-term debt (Note 7)	183,376	159,714	93,616
Future income taxes (Notes 11 and 12)	130,302	21,145	10,770
Site restoration and abandonments (Note 8)	1,359	1,222	1,304
	366,476	232,665	130,816
SHAREHOLDERS' EQUITY			
Capital stock (Note 9)	94,472	89,505	70,532
Retained earnings	63,324	27,197	10,735
	157,796	116,702	81,267
	$ 524,272	$ 349,367	$ 212,083

On behalf of the Board

Director
Chairman of the Company

Director
Chairman, Audit, Finance and Risk Committee

See accompanying notes to the financial statements.

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

YEAR ENDED DECEMBER 31 ($000s)	2000	1999	1998
Revenue			
Oil and gas revenues	**$ 213,376**	$ 97,016	$ 30,545
Royalties, net	**(44,695)**	(16,105)	(2,790)
	168,681	80,911	27,755
Expenses			
Operating	**31,571**	20,521	7,476
General and administrative	**5,915**	4,222	1,517
Interest	**12,772**	6,939	1,023
Depletion, depreciation and amortization	**41,767**	20,160	6,671
	92,025	51,842	16,687
Earnings before taxes	**76,656**	29,069	11,068
Taxes			
Future income taxes, (Note 12)	**35,707**	11,782	4,262
Capital taxes	**890**	199	202
	36,597	11,981	4,464
Net earnings	**40,059**	17,088	6,604
Retained earnings, beginning of year	**27,197**	10,735	4,409
	67,256	27,823	11,013
Change in accounting policy, future income tax (Note 11)	**(380)**	–	–
Premium on redemption of shares (Note 9)	**(3,552)**	(626)	(278)
Retained earnings, end of year	**$ 63,324**	$ 27,197	$ 10,735
Earnings per share			
Basic	**$ 0.37**	$ 0.18	$ 0.07
Diluted (Note 10)	**$ 0.36**	$ 0.17	$ 0.06

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOW

YEAR ENDED DECEMBER 31 ($000s)	2000	1999	1998
Cash derived from (applied to)			
OPERATING			
Net earnings	**$ 40,059**	$ 17,088	$ 6,604
Depletion, depreciation and amortization	**41,767**	20,160	6,671
Future income taxes	**35,707**	11,782	4,262
Cash flow from operations	**117,533**	49,030	17,537
Change in non-cash working capital (Note 14)	**(13,346)**	(11,201)	(5,159)
	104,187	37,829	12,378
FINANCING			
Proceeds from share issues, net	**11,844**	18,126	13,824
Proceeds from long-term debt, net	**23,662**	66,098	51,847
Redemption of common shares	**(5,564)**	(1,187)	(562)
Repayment of notes receivable	**–**	–	195
	29,942	83,037	65,304
INVESTING			
Property and equipment additions	**(118,153)**	(71,216)	(40,120)
Corporate acquisitions (Note 3)	**–**	(74,594)	(91,395)
(Acquisitions) dispositions, net	**(241)**	15,351	61,613
Site restoration	**(368)**	(507)	–
	(118,762)	(130,966)	(69,902)
Change in non-cash working capital (Note 14)	**(307)**	(4,828)	1,701
Working capital acquired (Note 3)	**–**	(132)	(9,481)
	(119,069)	(135,926)	(77,682)
Increase (decrease) in cash	**15,060**	(15,060)	–
Current bank debt, beginning of year	**(15,060)**	–	–
Current bank debt, end of year	**$ –**	$ (15,060)	$ –
Cash flow from operations per share			
Basic	**$ 1.10**	$ 0.50	$ 0.20
Diluted (Note 10)	**$ 1.06**	$ 0.49	$ 0.19

See accompanying notes to the financial statements.

1 NATURE OF OPERATIONS

The Company is engaged primarily in the exploration for and production of petroleum and natural gas reserves in a single cost centre being Western Canada.

2 SIGNIFICANT ACCOUNTING POLICIES

a) Basis of presentation

The financial statements for the comparative years include the accounts of Compton Petroleum Corporation (the "Company") and its wholly-owned subsidiaries, Compton Energy Inc. (formerly J.M. Huber Canada Limited) and Compton Oil & Gas Corporation (formerly Coparex Canada Ltd.). On January 1, 1999 and 2000, the Company wound-up Compton Energy Inc. and Compton Oil & Gas Corporation, respectively. Under the terms of the wind-up, all the assets and properties of the subsidiaries were transferred to the Company and the Company assumes all of their liabilities and obligations. Combined operations will continue in the single corporate entity, Compton Petroleum Corporation.

b) Petroleum and natural gas properties

i) Capitalized costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Costs include lease acquisition costs, geological and geophysical expenses, interest on debt directly related to certain acquisitions, and costs of drilling both productive and non-productive wells. Proceeds from the sale of properties will be applied against capitalized costs, without any gain or loss being realized, unless such sale would significantly alter the rate of depletion and depreciation.

ii) Depletion and depreciation

Depletion of exploration and development costs and depreciation of production equipment is provided using the unit-of-production method based upon estimated proved petroleum and natural gas reserves. The costs of significant undeveloped properties are excluded from costs subject to depletion. For depletion and depreciation purposes, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Depreciation of office equipment is provided for on a declining-balance basis at 20% per annum.

iii) Ceiling test

In applying the full cost method, the Company calculates a ceiling test whereby the carrying value of petroleum and natural gas properties and production equipment, net of recorded future income taxes and the accumulated provision for site restoration and abandonment costs, is compared annually to an estimate of future net cash flow from the production of proved reserves. Net cash flow is estimated using year end prices, less estimated future general and administrative expenses, financing costs and income taxes. Should this comparison indicate an excess carrying value, the excess is charged against earnings as additional depletion and depreciation.

iv) Future site restoration and abandonment costs

Estimated costs of future site restoration and abandonments, net of recoveries, are provided for over the life of proved reserves on a unit-of-production basis. An annual provision is recorded as additional depletion and depreciation. The accumulated provision is reflected as a non-current liability and actual expenditures are charged against the accumulated provision when incurred.

c) Financial instruments

Financial instruments of the Company consist mainly of accounts receivable and other, notes receivable, accounts payable and accruals and bank debt. Unless otherwise disclosed, there are no significant differences between the carrying value of these financial instruments and their estimated fair value.

From time to time, the Company may employ financial instruments to manage exposure related to Canada/U.S. exchange rates and commodity prices. Gains and losses on exchange rates and commodity price hedges are included in revenues upon sale of the related production.

d) Joint operations

Certain petroleum and natural gas activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

e) Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future income tax liability is increased and capital stock is reduced by the estimated tax benefits transferred to shareholders.

f) Per share amounts

Basic earnings per common share and cash flow from operations per common share are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments, in accordance with new standards approved by the Canadian Institute of Chartered Accountants, see Note 10.

g) Use of estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make assumptions and estimates that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from and affect the results reported in these financial statements.

h) Hedging activities

Settlement of crude oil and natural gas swap agreements, which have been arranged as a hedge against commodity price and currency fluctuations, are reflected in product revenues at the time of sale of the related hedged production.

i) Income taxes

Income taxes are recorded using the liability method of tax allocation. Future income taxes are calculated based on temporary timing differences arising from the difference between the tax basis of an asset or liability and its carrying value using tax rates anticipated to apply in the periods when the timing differences are expected to reverse, see Note 11.

3 ACQUISITION

1999 – Coparex Canada Ltd.

On December 1, 1999 the Company acquired all of the issued and outstanding shares of Coparex Canada Ltd. ('Coparex'), for cash consideration of $49,833,609. Coparex, a privately owned corporation, was engaged in oil and gas exploration activities primarily in Alberta. The transaction has been accounted for by the purchase method and the financial statements include the results of the operations from date of acquisition. The fair value of the assets acquired is as follows:

	($000s)
Property and equipment	
Oil and gas reserves and facilities	$ 64,421
Undeveloped lands	10,173
	74,594
Working capital	132
Long-term debt	(24,893)
Net assets acquired	$ 49,833

4 ASSETS HELD FOR SALE

During the fourth quarter of 1999, in relation to the acquisition of Coparex Canada Ltd., the Company commenced a program of divestiture of non-core petroleum and natural gas assets. As at December 31, 1999 a total of $18,870,000 of such transactions were in various stages of completion with effective dates as at December 31, 1999. This amount has been reclassified from property and equipment to assets held for sale. In 2000, proceeds received from the sale of these assets were applied to eliminate the Company's outstanding subordinated bridge facility.

5 NOTES RECEIVABLE

The Company granted loans to officers of the Company to facilitate the exercise of options, granted prior to the Company filing an Initial Public Offering, to acquire common shares of the Company.

The loans are demanding in nature and repayable at the earlier of such demand or their Maturity Date being the date the officer ceases to be employed by the Company. The loans are non-interest bearing until the Maturity Date, at which time interest is calculated monthly at the bank prime rate plus 5%. The Company holds in trust the shares, issued on exercise of the options, as security for the loans. As at December 31, 2000 the amount outstanding for these loans was $150,000 (1999 - $150,000).

6 PROPERTY AND EQUIPMENT

	2000 ($000s)	1999 ($000s)
Exploration and development costs	**$ 455,565**	$ 299,247
Accumulated depletion	**(64,058)**	(26,582)
	391,507	272,665
Production equipment and processing facilities	**55,529**	25,566
Office equipment	**2,154**	1,836
	57,683	27,402
Accumulated depreciation	**(6,293)**	(2,507)
	51,390	24,895
	$ 442,897	$ 297,560

The Company does not capitalize any portion of its general and administrative expenses. Interest expense of $713,000 (1999 - $173,780) associated with certain property acquisitions and processing facilities has been capitalized.

Future capital expenditures of $37,078,000 (1999 - $26,657,000), as estimated by independent engineers, relating to the development of proved non-producing reserves have been included in costs subject to depletion, and undeveloped properties with a cost of $72,309,000 (1999 - $55,605,878), included in exploration and development costs, have not been subject to depletion.

7 CREDIT FACILITIES

	2000 ($000s)	1999 ($000s)
Subordinated bridge facility	**$ -**	$ 15,060
Extendible credit facility	**183,376**	159,714
Total	**$ 183,376**	$ 174,774

Bank debt

As at December 31, 2000, the Company had authorized syndicated extendible credit facilities, with Canadian chartered banks, in the amount of $192,000,000 (1999 - $165,000,000). The facilities are comprised of a $182,000,000 (1999 - $155,000,000) production facility and a $10,000,000 working capital facility. Advances under the facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the bank's prime lending rate plus applicable margins or bankers' acceptance rates plus stamping fees. The margins and stamping fees vary depending on financial statement ratios and are currently set at 0.0% and 0.875% respectively. The facilities mature on June 30, 2001. The facilities are subject to annual review which is currently ongoing. The Company and its lenders anticipate the facilities will be extended with similar terms and conditions. Accordingly the facilities, in their entirety, have been classified as a non-current liability.

The credit facilities are secured by a first fixed and floating charge debenture in the amount of $325,000,000 covering all the Company's assets and undertakings.

8 SITE RESTORATION AND ABANDONMENTS

At December 31, 2000 total future removal and site restoration costs to be accrued over the life of the remaining proved reserves were estimated, net of recoveries, at $5,434,179 (1999 - $5,414,366) of which $1,359,000 (1999 - $1,222,000) have been accrued. This estimate is subject to change based on amendments to environmental laws as new information concerning operations becomes available.

9 CAPITAL STOCK

a) Authorized

Unlimited number of common shares
Unlimited number of preferred shares, issuable in series

b) Issued and outstanding

	2000		1999	
	Number of Shares	**Amount ($000s)**	Number of Shares	Amount ($000s)
Common shares				
Balance, beginning of year	**108,047,882**	**$ 89,505**	96,308,715	$ 70,532
Issued for cash, net	**3,075,100**	**6,825**	9,683,635	15,575
Issued for property	**30,000**	**78**	-	-
Issued for cash on exercise of warrants	-	-	2,000,000	3,200
Issued for cash on exercise of options	**56,667**	**76**	822,832	758
Repurchased for cash	**(2,426,000)**	**(2,012)**	(767,300)	(560)
Balance, end of year	**108,783,649**	**$ 94,472**	108,047,882	$ 89,505

Common shares issued for cash include 3,075,100 (1999 - 5,583,655) common shares issued on a flow-through basis. Under the terms of the current year flow-through agreements, the Company is required to expend the proceeds of $12,454,155 on qualifying oil and natural gas expenditures prior to December 31, 2001. As at December 31, 2000, the Company has not incurred any qualifying expenditures.

During the year the Company repurchased for cancellation 2,426,000 common shares at an average price of $2.29 per share (1999 - 767,300 shares at an average price of $1.55 per share), pursuant to a normal course issuer bid. The excess of the purchase price over book value has been charged to retained earnings.

c) Outstanding options

The Company has implemented a Stock Option Plan, for directors, officers and employees. 9,000,000 common shares were reserved for issuance to eligible participants. At December 31, 2000, 6,352,335 (1999 - 6,081,334) options with exercise prices between $0.60 and $2.30 were outstanding and exercisable at various dates to August 2010. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

	2000		1999	
Fixed Options	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	6,081,334	$ 1.00	7,478,334	$ 0.96
Granted	500,000	$ 2.30	700,000	$ 1.83
Exercised	(56,667)	$ 1.34	(822,832)	$ 1.34
Cancelled	(172,332)	$ 1.45	(1,274,168)	$ 1.38
Outstanding at end of year	6,352,335	$ 1.08	6,081,334	$ 1.00
Options exercisable at year end	5,719,001	$ 1.00	4,981,668	$ 0.77

d) Outstanding warrants

In 1998, in conjunction with the disposition of certain facilities, the Company issued share purchase warrants to a third party, which entitled the holder to acquire 3,000,000 common shares of the Company. As at December 31, 2000, 1,000,000 (1999 - 1,000,000) warrants were outstanding at an exercise price of $1.75 per share. The warrants may be exercised on the basis of 10,000 warrants for each $250,000 paid to the Company as an incentive fee under the terms of the disposition.

e) Shareholder rights plan

The Company has a Shareholder Rights Plan to ensure all shareholders are treated fairly in the event of a take-over offer or other acquisition of control of the Company.

Pursuant to the Plan, the Board of Directors authorized and declared the distribution of one Right in respect of each common share outstanding as at January 28, 1997. In the event that an acquisition of 20% or more of the Company's shares is completed and the acquisition is not a permitted bid, as defined by the Plan, each Right will permit the holder to acquire, at the exercise price of $8.00, such number of common shares as have a market value equal to twice the exercise price.

10 PER SHARE AMOUNTS

The Canadian Institute of Chartered Accountants has approved a new standard for the computation, presentation and disclosure of per share amounts. In the fourth quarter of 2000 the Company retroactively adopted the new standard. Under this standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options, warrants and other dilutive instruments. Under the treasury stock method only "in the money" dilutive instruments impact the dilution calculations.

The weighted average number of common shares outstanding during the year, calculated under the treasury stock method, used in computing per share basic earnings and cash flow from operations was 106,903,862 (1999 - 97,409,417). In computing diluted earnings and cash flow from operations per share, 3,741,616 shares were added to the weighted average number of common shares outstanding during the year ended December 31, 2000 (1999 - 3,390,764 shares) for the dilutive effect of employee stock options and warrants. No adjustments were required to reported earnings or cash flow from operations in computing diluted per share amounts.

Prior period diluted earnings per share and cash flow from operations per share have been restated for this change in accounting policy. If the imputed earnings method had been used to calculate these amounts, the reported amounts would have been:

	2000	1999	1998
Diluted earnings per common share	**$ 0.35**	$ 0.16	$ 0.06
Diluted cash flow from operations per common share	**$ 1.03**	$ 0.47	$ 0.17

11 FUTURE INCOME TAXES

Effective January 1, 2000, the Company adopted the new recommendations of the Canadian Institute of Chartered Accountants with respect to accounting for future income taxes. Under the new recommendations the liability method of tax allocation is used, which is based upon the difference between financial and tax bases of assets and liabilities. Previously, the deferred method was used which was based upon differences between the timing of reporting income and expenses for financial and income tax purposes.

The Company has adopted this change in accounting policy retroactively, without restating the financial statements of prior periods. As a result, the Company recorded a reduction in retained earnings of $0.4 million, an increase in property and equipment of $68.1 million and an increase in the future income tax liability, previously the deferred income tax liability of $68.5 million, as at January 1, 2000.

The adjustments were mainly the result of future tax costs relating to acquisitions where the tax basis acquired was less than the purchase price, and the tax consequence of flow-through share issues.

12 INCOME TAXES

a) Provision for income taxes

	2000 ($000s)	1999 ($000s)
Earnings before taxes	**$ 76,656**	$ 29,069
Expected tax expense at combined federal and provincial rate of 44.62%	**$ 34,204**	$ 12,965
Increase (decrease) resulting from:		
Non-deductible Crown charges	**16,915**	7,831
Depletion of assets without a tax base	**8,661**	1,035
Royalty tax credits included in income	**(291)**	(602)
Resource allowance	**(17,486)**	(7,207)
Resource allowance rate deduction	**(1,070)**	-
Provincial royalty deduction	**(2,987)**	-
Other	**(2,239)**	(2,240)
Provision for future income taxes	**$ 35,707**	$ 11,782

b) Future income taxes

Future income taxes consist of the following temporary differences:

	2000 ($000s)
Property and equipment	$ 136,407
Resource allowance rate reduction	(1,070)
Provincial royalty deduction	(2,988)
Share issue costs	(1,385)
Future site restoration	(662)
Future income taxes	$ 130,302

c) Available tax deductions

The Company has available the following approximate amounts which may be deducted, at the annual rates indicated, in determining taxable income of future years:

	Rate	2000 ($000s)	1999 ($000s)
Canadian exploration expense	100%	$ -	$ 25,393
Canadian development expense	30%	$ 29,658	$ 44,741
Canadian oil and gas property expense	10%	$ 70,068	$ 70,815
Undepreciated capital cost	25%	$ 36,533	$ 30,346
Share issue costs	20%	$ 3,104	$ 4,303

13 FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in commodity prices, interest rates and Canada/U.S. dollar exchange rates. The Company, when appropriate, utilizes financial instruments to manage its exposure to these risks.

a) Commodity price risk management

i) Crude oil

During 2000, the Company had in place commodity swap arrangements which fixed the price at $21.75 U.S. per barrel of crude oil on 1,000 barrels per day from January 1, 2000 to December 31, 2000 and 1,000 barrels per day from April 1, 2000 to September 30, 2000. Currently no swap arrangements have been entered into for 2001.

ii) Natural gas

During 2000, the Company entered into fixed price contracts for the sale of 7,500 GJs per day at an average price of $3.37 per GJ for the period from January 1, 2000 to October 31, 2000.

Currently the Company has entered into two fixed price contracts on a cost-less collar basis as follows:

Volume	Price/GJ	Period
10,000 GJs per day	$5.50 to $9.05	Nov. 1, 2000 to Mar. 31, 2001
6,000 GJs per day	$6.50 to $8.18	Apr. 1, 2001 to Oct. 31, 2001

b) **Credit risk management**

Accounts receivable include amounts receivable for oil and gas sales which are generally made to large credit worthy purchasers, and amounts receivable from joint venture partners which are recoverable from production. Accordingly, the Company views credit risks on these amounts as low.

The Company is exposed to losses in the event of non-performance by counter-parties to these financial instruments. The Company deals with major institutions and believes these risks are minimal.

14 CASH FLOW

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

	2000 ($000s)	1999 ($000s)	1998 ($000s)
Accounts receivable and other	**$ (29,568)**	$ (26,427)	$ (16,645)
Accounts payable and accruals	**15,915**	10,398	13,187
	$ (13,653)	$ (16,029)	$ (3,458)
Operating activities	**$ (13,346)**	$ (11,201)	$ (5,159)
Investing activities	**(307)**	(4,828)	1,701
	$ (13,653)	$ (16,029)	$ (3,458)

Amounts actually paid during the year related to interest expense and capital taxes were as follows:

	2000 ($000s)	1999 ($000s)	1998 ($000s)
Interest paid	**$ 13,639**	$ 6,576	$ 2,845
Capital taxes paid	**$ 470**	$ 314	$ 226

15 COMMITMENTS

During the year, the Company entered into an agreement to lease certain oil and gas equipment under an operating lease expiring in 2003. The minimum rental commitments, excluding sublease income, under operating leases are as follows:

2001	$ 1,121
2002	1,121
2003	561
Total minimum payments required	$ 2,803

Five Year SUMMARY

FINANCIAL

($000s except per share amounts)

	2000	1999	1998	1997	1996
Revenue, net	**168,681**	80,911	27,755	15,220	3,493
Net earnings	**40,059**	17,088	6,604	3,725	540
Earnings per share, basic	**0.37**	0.18	0.07	0.06	0.02
Cash flow from operations	**117,533**	49,030	17,537	10,036	1,780
Cash flow per share, basic	**1.10**	0.50	0.20	0.16	0.06
Shareholders' equity	**157,796**	116,702	81,267	67,027	23,946
Net debt	**153,590**	158,641	93,308	44,920	836
Capital expenditures	**118,472**	130,459	69,901	92,987	21,514
Share data					
High ($)	**3.80**	3.00	1.95	2.25	1.10
Low ($)	**1.31**	1.20	1.10	0.75	0.65
Close ($)	**3.77**	2.40	1.65	1.60	0.85
Weighted average outstanding (000s)	**106,904**	97,409	88,731	62,358	29,626
Volume Traded (000s)	**48,917**	46,314	38,226	30,704	4,100
Volume Traded (average per day)	**195,000**	184,000	152,000	123,000	76,000

OPERATING

	2000	1999	1998	1997	1996
Production					
Natural gas (mmcf/d)	**85.1**	63.7	33.1	16.2	4.7
NGLs (bbls/d)	**1,897**	1,718	611	300	87
Oil (bbls/d)	**4,408**	2,756	223	191	158
Total (boe/d, 10:1)	**14,812**	10,844	4,146	2,113	713
Total (boe/d, 6:1)	**20,488**	15,091	6,351	3,194	1,025
Established reserves					
Natural gas (bcf)	**337.5**	289.0	235.3	157.7	54.7
NGLs (mbbls)	**5,352**	4,814	4,651	4,023	1,890
Oil (mbbls)	**11,367**	10,801	5,736	769	1,057
Total (mboe, 10:1)	**50,473**	44,513	33,921	20,562	8,417
Total (mboe, 6:1)	**72,969**	63,778	49,604	31,075	18,591
Wells drilled					
Natural gas	**56**	43	11	7	2
Oil	**10**	17	3	2	1
Dry and abandoned	**30**	23	9	2	1
Total	**96**	83	23	11	4
Net	**78.3**	71	18.3	10.5	3.3
Undeveloped Land (net acres)	**590,517**	502,404	314,281	139,769	63,140

Corporate

Hilary Shipley, Ann McManus, Gordaleen Harbourne, Ron Pan, Dolores Benedictson, Moira Schneider, Dean Bernhard, Diane Mack, Liz Tanouye, Theresa Kosek, Kim Gardner, Kari Gertz, Della Kennedy, Lori Teekasingh, Shannon Mandryk, Jason Day

Operations & Field

Trevor Keller, Charles Empringham, Ryan Phillips, Wade Mrochuk, Don Prestie, Jim Ferguson, Kerry Shearer, Gene Englot, Gerald Mezzo, Clark Williams, Rod Kenney, Gordon Gorzitza

Not available for photo:
Alison Egeland,
Gerald Deines,
Darryl Jones,
Tim Berg,
Ken Berg,
Dale Richardson,
Darin McLarty

Operations

Shubha Karsanji, Terry Mah, Theresa Viani, Kelly O'Hearn, Lee Ann Cox, Greg Shpytkovsky, Barb Kisilowski, Shaun Wyzykoski, Megan Kane, Ray Lee, Carol Moore, Gary Follensbee, Tracey Dawson, Karen Riep, Darrin Hanik, Cristina Barney, Pary Weiler

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Executive V.P. & President & C.E.O.
Pipelines & Midstream
Westcoast Energy Inc.

J.W. PRESTON
Sun Microsystems

J.T. SMITH, P.GEOL.[3]
Independent Businessman

The Board has established an Audit, Finance and Risk Committee, a Reserves, Safety and Environment Committee, and a Corporate Governance and Compensation Committee. Each committee consists of all directors of the Corporation, other than Mr. Sapieha, each of whom are unrelated to the Company.

1 Chairman, Corporate Governance and Compensation Committee

2 Chairman, Audit, Finance and Risk Committee

3 Chairman, Reserves, Safety and Environment Committee

OFFICERS

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President & C.E.O.

N.G. KNECHT, C.A.
V.P. Finance & C.F.O.

K.N. DAVIES, P. GEOPH.
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OUTTRIM SZABO ASSOCIATES LTD.

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STOCK EXCHANGE LISTING

THE TORONTO STOCK EXCHANGE
Trading Symbol: CMT

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